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Trends in State Utility Regulation Affecting Renewable Energy

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INTRODUCTION

Staff and consultants of the Renewable Energy Institute have conducted a comprehensive review of the environment in which renewable energy technologies are being introduced for power production. Under contract with the Solar Energy Research Institute, the study has been organized into three major components:

- An analysis of investment in renewable energy technology projects and companies by institutional investors, concentrating on the investment criteria used and the public perceptions about renewable energy and government policy.
- An analysis of how electric utility planners make decisions about renewable energy technologies.
- An analysis of the impact of state utility regulatory decisions on renewable energy development.

Three separate reports have been produced as a result of this study. This volume, which is the third component, and titled *Trends in State Utility Regulation Affecting Renewable Energy*, analyzes the current regulatory environment at the state level and the way renewable energy resources and technologies are treated. The report identifies numerous regulatory issues and refers to approaches taken by different state utility commissions regarding those issues. It is not intended to provide a comprehensive review of all state regulatory rulings on these issues.

The study has identified several key findings. First, a significant *transition* is underway toward more active intervention in state regulatory proceedings that is likely to have a profound effect on future investments by utilities and non-utility parties. This transition has resulted in a number of trends that affect, and will continue to affect, renewable energy development. Second, the implementation of the federal Public Utility Regulatory Policies Act of 1978 (PURPA), and the subsequent introduction of non-utility owned and operated cogeneration and small power production sources (many of which employ renewable energy technologies) have established an evolutionary process that will continue to be modified with increased experience. Third, the federal mandate to encourage independent power production has afforded state regulators additional authority in the economic regulation of electric utilities and justified the development of renewable energy sources "in the public interest." Finally, the transition in the regulatory environment at the state level may be occurring more rapidly than technological development of renewable energy systems. Thus, the technical and economic requirements renewable energy systems must meet are being modified, in some cases, before the technologies are commercially available.

In sum, decisions and rulings of state regulators are having a major and increasing impact on the future prospects for the development and introduction of renewable energy technologies in the utility sector.

I. OVERVIEW

A. A Transformation in State Utility Regulation

In recent years, electric utility regulation at the state level has changed from a relatively simple and straightforward practice to one of increased oversight, mediation, and implementation of public policy. The days have gone in which utility regulation was relatively non-controversial, when utilities and their customers enjoyed stable or declining costs, and state regulators saw their objective—to provide essential services to the public at the best possible price—being fulfilled through the economic decisions of utility managers, with

little or no need for regulatory end-use intervention. Today, under the pressures of rising electric retail rates, excess generating capacity due to increased efficiency and reductions in customer demand, increased regulation at the federal level, and the emergence of customer- and independently-owned generation, state regulators have greatly increased their role in the utility decisionmaking process. As state regulators have recognized that renewable energy technologies are viable generation options, they have concluded that encouraging their development and implementation is in the "public interest." Arriving at this realization has unquestionably encouraged more rapid deployment of these technologies.

Historically, state utility regulation remained relatively unchanged since its inception in the early 1900s. It provided jurisdictional utilities with an exclusive right to generate, transmit, distribute, and sell electricity. In return for this monopolistic control, utility profits were restricted to a regulated rate of return on capital investment. Retail rates were based on the embedded cost of all generation and transmission expenses plus variable fuel and operating costs.

During the 1950s and 1960s, state commissions routinely set rates at "reasonable levels" based on actual costs. Through efficiency improvements and new technology, utilities attempted to reduce the costs of generating electricity and to increase profits within the established rate structure. Occasionally, when utility profits became excessive, regulators ordered a rate decrease. Utilities were satisfied with this system since their profits ranged from adequate to more than adequate; ratepayers were satisfied because service was good and rates were stable or declining; and state regulators generally felt comfortable under the benign impression that utilities, in their efforts to improve profitability, were operating efficiently.

This scenario was altered in the 1970s and early 1980s in response to increasing costs associated with generating electricity, more active consumer and environmental intervention in utility rate cases, and, ultimately, a federal mandate for state utility commissions to implement PURPA. Electric utilities and their regulators suddenly found themselves in disagreement as to the best means to achieve reliable, low-cost electricity for retail customers. At the same time, and for similar reasons, state regulators began to give greater importance to public policy considerations in the regulation of electrical energy. Mandating increased utilization of renewable energy has been an integral part of state regulatory reform. This has been achieved directly through the modification of utility resource plans, increasing expenditures for research and development, and providing incentives for non-utility development of renewables, such as setting attractive utility buy-back rates. Indirect support has been provided in the form of regulatory restrictions on the deployment of conventional central-station powerplants.

Today, several trends in state utility regulation have emerged, each with particular significance for renewable energy. These trends include diversification of energy resources; reduction in the economic risks incurred by ratepayers; encouragement of independent, non-utility power production sources; stimulation of competition in the power generation market to drive electricity costs down; and adoption of "least-cost planning" principles as the basis for future resource planning decisions. PURPA is an important component of these trends, and a key element in the future of state utility regulation.

B. Encouragement of Independent Power Production

Perhaps the most influential piece of federal regulatory legislation affecting renewable energy in the past decade has been PURPA.[1] The U.S. Congress amended the Federal Power Act to allow non-utility parties to develop certain technologies and resources for power generation without being regulated as electric utilities. Because of PURPA, a new player emerged in the utility sector: the independent power producer. By requiring utilities to interconnect with independent power projects, purchase output at the utility's avoided cost, and supply back-up service, PURPA stimulated non-utility parties (some of them former customers of utilities) to supplement utility-generated electricity with power from cogeneration and renewable energy systems.

PURPA can be seen as a model of federalism. That is, guidelines and limits were established at the federal level, but the actual authority for implementation (particularly rate setting) was left to the states. As a result, there is no uniform approach to PURPA implementation. Some have merely fulfilled the minimum requirements issued by the Federal Energy Regulatory Commission (FERC) by letting their utilities determine the appropriate rates and contract terms with independent energy producers. This has occurred in capacity-rich states with current low marginal generating costs, and those where the level of non-utility development is adequate in the eyes of the state regulators. Others have established strict guidelines on how avoided costs should be calculated and established for standard long-term contracts. Some states have supplemented PURPA with state legislation to further encourage development of alternative sources of energy. The greatest encouragement is usually found in a perceived need for more generating capacity , or to meet a target market penetration level (e.g., a percent of average peak demand), as a means of attaining a more diversified supply mix. Cogeneration is also considered to be a means of providing a more efficient use of energy.

To date, state laws that relate to PURPA have authorized state commissions to increase economic incentives; expanded the definition of "qualifying facilities" for purposes of eligibility; altered the level of allowed utility involvement in independent energy projects; and addressed issues not included in the federal legislation. State PURPA laws may also have been developed to insulate the state implementation rules from future legal challenges, especially when differences with FERC rules exist, or amendments to the federal regulations.

C. Resource Diversification

Following the energy crisis of 1973-74 and corresponding increased cost of oil for power generation, federal and state governments instituted programs intended to diversify the energy resource mix used to generate electricity. PURPA, accompanied by the Power Plant and Industrial Fuel Use Act of 1978, sought to create incentives and disincentives in the regulatory environment as a means of encouraging this diversification. The Fuel Use Act restricted utilities from building oil- or natural gas-fired power plants, while PURPA encouraged development of indigenous renewable resources, and more efficient use of fossil fuels through cogeneration of electric and thermal energy.

Some states, particularly those with a high dependence on oil, felt it necessary to supplement the federal requirements. For example, the New Hampshire Limited Electrical Energy Producers Act requires the Public Service Commission to provide for "small scale and diversified sources of supplemental electric power to lessen the state's dependence upon sources

1 Public Law 95-617; Stat. 3117 (1978).

which may, from time to time, be uncertain."[2] Similarly, the California Energy Commission was created, in part, to support development of a resource-balanced power generation system.

Some states have found that resource diversification has become a different type of issue as a result of the growth in independent power production stimulated by PURPA. For example, states that witnessed a substantial increase in the use of natural gas for cogeneration under PURPA have realized it may be necessary to provide preferential treatment for technologies using renewable energy resources. In Texas, where natural gas cogeneration systems dominate the state's independent power production market, the Public Utilities Commission has directed utilities to consider renewable energy and municipal solid waste projects first, when considering the need for additional capacity. Similarly in Connecticut, utilities are instructed to distinguish renewable resources and refuse fueled projects from fossil fuel projects based on the state's policy to limit their dependence upon fossil fuels.

D. Risk Reduction for Utility Ratepayers

State utility commissions have become acutely aware of pressures to reduce the costs and economic risks ratepayers face. Many regulatory bodies have dealt with these pressures by invoking their authority to limit cost recovery of utility construction programs through prudency tests and disallowance of costs of acquiring surplus capacity. With regard to longer-range costs and risk for ratepayers, a call for increased research and development of new technologies acknowledges concern state regulators hold about inadequate technology development. Regulators have also recognized the risks and benefits to ratepayers of value-based pricing for electric services, as defined under PURPA.

In the past, traditional "cost-of-service" pricing allowed utilities to recover reasonably incurred capital investment and operating costs, plus a return on investment. PURPA stipulated a new method for pricing power from qualifying facilities (QFs), called "value-based pricing." To determine an economic (and non-economic) value for electricity the state PUC reviews costs that utilities can avoid by not constructing additional powerplants, reducing the output of existing facilities or by purchasing electricity from other sources. The profits to the owner of the QF are determined by the actual performance and costs of the project in light of prices established for the energy. In such a case, the risk of downtime and below-par operation of a power plant is transferred to its owners.

Where market penetration increased and a significant number of non-utility owned and operated projects have been incorporated into utility resource plans, state regulators have come to realize they should be concerned about protecting ratepayers from the risks of QF non-performance. Several states now include security clauses in standard contracts to ensure that ratepayers are protected. The Massachusetts Department of Public Utilities, for example, has listed security provisions that utilities should consider for ranking QF projects in a competitive bidding process used in that state.

The questions about risk and assignment of risks that have arisen since PURPA was implemented have created a complex decisionmaking environment for regulators, independent power producers, and utility planners. Technical and economic risks associated with unfamiliar renewable energy technologies are likely to continue to be the subject of regulatory concern, whether a project is developed by utility or non-utility parties.

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2 New Hampshire Rev. Stat. Ann. Section 3 et seq. Supp. (1982) "Declaration of Purpose," Cited in Sarah P. Voll (New Hampshire Public Service Commission), "Forecasting Electric Power from Renewable Resources," *Public Utilities Fortnightly*. March 24, 1984, p. 29.

E. Increased Competition

The concept of introducing increased competition in the power generation market is gaining attention among state regulators. When marginal costs for generating electricity were in decline, the monopoly structure of the utility industry fulfilled the regulators' objective of keeping retail rates down. However, as marginal cost trends have reversed themselves in recent years, competition has been looked upon as a means to hold prices down for ratepayers. PURPA, in particular, has provided regulators with a taste of competition in the generation of electricity. By deregulating certain non-utility sources of power, regulators now anticipate that technological innovation and alternative power production can offer lower-cost power supply options.

One regulator has suggested that a "devolution" in the generation of electricity be pursued by changing the ownership of power plants from utilities to other, private investors. Under this scheme, competition among generation sources would be established by using a centralized dispatch strategy, called economy brokerage, and mandatory wheeling. Illinois Commissioner Stanford Levin has observed: "The introduction of competition into electricity generation will provide significant advantages to ratepayers and the utilities. More risk will be transferred to investors and the prices will be lower for ratepayers, strong incentives will be provided for efficient planning and operation."[3] Fellow Illinois Commissioner, Chairman Philip O'Conner, also supports competition in the utility industry, pointing out that, "Consumers and generators will have clearer price signals from a market based on competition than on one based on regulation."[4]

Another approach to competition advocated by some state commissions involves competitive bidding in the setting of buy-back rates for qualifying facilities (QFs). A utility would set an initial offering for capacity bid at the price it could produce or acquire a given increment of generating capacity (avoided cost). QFs then would submit contract proposals at the utility's bid price or below. Proponents of this process expect that competition among QFs for limited capacity increments, based on cost and other factors, would result in the lowest cost power supply for ratepayers. Maine, Massachusetts, and California have adopted variations of this approach. More experience will be required to see how they affect development of renewable energy technologies. Some analysts expect only the most commercially mature renewable energy technologies to benefit from competitive bidding. New technologies would probably still require some special dispensation to break into this competitive environment.

F. Introduction of Least-Cost Planning

Another trend in state utility regulation is consideration and adoption of "least-cost planning" criteria to guide selection of future resource options. The least-cost planning concept is based on the premise that the market is not capable of guiding utility resource choices without specific guidance on improving end-use efficiency. Although the definition of "least-cost" differs among states, a purpose common to all is to evaluate supply- and demand-side options in terms of their impact on utility retail rates. It should be noted that many advocates of least-cost

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3 Stanford L. Levin, "A Strategy for the Devolution of Electricity Generation," Illinois Commerce Commission, May 1985, p. 2

4 "Free Market Should Rule, Says Illinois Regulator Philip O'Conner," *Electric Light and Power*. June 1985, p. 20.

planning come to it principally from the demand-side perspective. It is also noteworthy that this approach has also been pursued by electric utilities without pressure from regulations.

The interest in least-cost planning regulations was confirmed in 1984 when the National Association of Regulatory Utility Commissioners (NARUC) passed a resolution which "bases the determination of need for new facilities on the development of a least cost supply plan which evaluates and incorporates all cost effective conservation, load management, and alternative energy sources."[5] The resolution calls for the development of resources in the following order: 1) conservation, 2) renewable resources, 3) use of waste heat or high fuel conversion efficiency, and 4) all other resources. The issue has risen to national importance with the initiation of the Least-Cost Utility Planning (LCUP) program at the U.S. Department of Energy.

Nevada and Wisconsin are among the states that have adopted least-cost planning regulations. Nevada leaves determination of resource priorities to the state's utilities and calls on the utilities to perform a cost/benefit analysis comparing traditional and non-traditional supply options. Wisconsin is more aggressively promoting a least-cost planning methodology that stipulates that socioeconomic and environmental impacts (such as health, safety, employment, etc.) be included in the determination of relative values. In view of the popular support for cost-based analysis aimed at reaching the lowest possible electricity costs, many more states are likely to embrace a least-cost planning approach to utility resource planning.

While renewable energy sources have been explicitly included in state least-cost planning regulations, near-term cost emphasis is likely to discount the value of capital-intensive renewable energy technologies. In such cases, non-utility development of these technologies with long-term power-purchase contracts may well prove to be more attractive than utility rate basing of capital expenditures. Better information on life-cycle costs for renewable energy technologies will help regulators assign realistic values to these supply sources.

In summary, this Section I Overview has listed key aspects of the transformation underway in state utility regulation, and indicated how certain trends may affect development of renewable energy. Many of these trends have resulted from the common approaches taken by state utility commissions to implement PURPA. Section II discusses a number of issues related to implementation of PURPA and the implications for renewable energy development of various state rulings. Section III discusses renewable energy in the context of utility regulation practices and procedures outside PURPA. While the two forms of utility regulation have developed independantly, treatment of PURPA and non-PURPA issues are increasingly being considered in the context of overall regulatory reform.

II. PURPA AND RELATED ISSUES

State utility regulation has changed markedly in the eight years since Congress passed the Public Utility Regulatory Policies Act (PURPA) of 1978. Charged with increased responsibility to implement the federal law, state regulators found a number of new issues relating to the addition of independent power production sources to the more traditional sources

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5 "Resolution Supporting Adoption by State and Federal Regulatory Commissions of a Policy Mandating Electric and Gas Utilities to Develop and Submit for Approval Least-Cost Resource Plans," Resolution No. 7, National Association of Regulatory Utility Commissioners, 96th Annual Meeting, Los Angeles, CA, 1984.

of power generated by regulated electric utilities. The resolution of these issues by individual state utility commissions has and will continue to influence greatly the environment in which renewable energy systems are introduced in the utility sector.

A. Background

In 1978, Congress enacted Sections 201 and 210 of PURPA as a means of encouraging cogeneration and small power production. PURPA provides substantial benefits to cogeneration and small power producers, labeled "qualifying facilities" (QFs) under the Act. The Federal Energy Regulatory Commission (FERC) was authorized to promulgate rules and regulations for Sections 201 and 210 of PURPA. FERC, in turn, left to the state utility commissions and unregulated utilities certain responsibilities for implementing the final rules and regulations.

The FERC regulations treat cogeneration facilities and small power production facilities that use renewable energy differently. They define a "cogeneration facility" as one in which the equipment is used to produce electric energy and useful thermal energy for industrial or commercial heating or cooling purposes, in a sequential process. Cogeneration systems can use a wide range of fuels to produce power: e.g., oil, natural gas, coal, biomass, solid waste, geothermal energy, etc. Efficiency standards require that at least 5% of the energy output from a qualifying cogeneration facility be dedicated to "useful" thermal applications. No size (installed capacity) requirements have been established for qualifying cogeneration systems.

A qualifying small power production facility cannot have a combined capacity greater than 80 megawatts and must use biomass, waste, or renewable resources (including hydroelectric power from existing dams) as a primary energy source. In addition, the aggregate use of oil, natural gas, and coal by the renewable small power facility may not exceed 25 percent of the total energy input during any calendar year. Qualifying cogeneration and small power production facilities cannot be owned by an entity primarily engaged in the generation and sale of electric power, other than power solely from cogeneration or small power facilities.

Section 210 of PURPA requires that utilities purchase QF output at the utility's "avoided cost," provide back-up service to QFs at non-discriminatory rates, and interconnect with the QF as necessary to accomplish purchases from and power sales to the QF. The state utility commissions were left to prescribe specific terms and conditions for these requirements.

In addition, all qualifying cogeneration facilities and qualifying small power facilities under 30 megawatts are exempted from the Public Utilities Holding Company Act (PUHCA), the Federal Power Act (FPA), and state laws regarding financial or organizational regulations of electric utilities. This exemption does not apply in the following cases:

- Qualifying biomass small production facilities may be exempted from PUHCA and state laws, but not from FPA.

- Qualifying geothermal small power production facilities may be exempted from PUHCA, FPA, and state laws.

StatState utility commissions have applied different interpretations to their authority to encourage cogeneration and small power production. In many cases, variations in their approach can be traced to the degree of market penetration by cogeneration and small power production, and to perceptions about the need to provide greater or lesser encouragement for QF development. In recent Congressional testimony submitted by NARUC, Commissioner William Badger of Maryland noted:

"We [state regulators] are uniquely situated to effectuate the underlying intent of PURPA to encourage the use of energy-efficient technologies such as cogeneration and non-utility power from renewable resources...It is the bedrock principle of NARUC that those who are in the best position to balance the interests of utility ratepayers along with the mandate of PURPA to encourage cogeneration and small power production should be afforded to apply the framework of the law to unique local circumstances."[6]

B. Qualifying Facility Definition

To become a "qualifying facility" under Section 210 of PURPA, a cogeneration or small power production facility may be certified in either of two ways: 1) self-certification; or 2) FERC approval of a certification petition. The self-certification process may be pursued in the case of projects that clearly meet Section 201 requirements: the project developer simply submits pertinent project-related information to the FERC. When the project status is less certain, a more formal process must be pursued to allow FERC to decide eligibility for certification.

In the first years after PURPA was enacted, the FERC review process was the primary means by which project developers sought certification. This was due in large part to the need to provide financial backers with certainty about status of a project and a lack of precedents at FERC for certification of various types of projects. A FERC spokesperson has recently noted a trend toward greater use of the "self-qualifying" applications: "In cases of plants running on wind, solar, hydro, and geothermal, where there is little doubt about the energy source, and where other restrictions are clearly met [e.g., size and utility ownership limitations], an application has to qualify."[7] Consequently, many project developers are now self-certifying.

In a few cases, qualifying status has been questioned for small power production facilities using renewable energy resources. One case involved a FERC rule that established an area with a one-mile radius as the definition of "single site." The intent was to inhibit developers from breaking up a large project to qualify it as a collection of small power production facilities. A precedent was set for windfarm developers when an applicant proposed to install more than 30 MW of wind capacity not contained within a one-mile radius and submitted applications for certification of several sites. The applicant's site optimized the wind resource by placing the turbines on ridges that happened not to be within one mile of each other. FERC approved the application, noting that the ridges have "sufficient, distinct, and identifiable topographic and energy resource-related characteristics so that each constitutes a separate site."[8]

Another noteworthy decision by FERC involved a ruling on the use of fossil fuels in small power production facilities. Two separate applicants proposed using natural gas to enhance the renewable energy portion of their projects. One project was a solar thermal plant and the other a municipal solid waste (MSW) facility; the solar project was approved, the MSW facility was not. In the solar thermal project, a duel-inlet steam turbine was used to supplement the solar-generated steam during periods of low solar gain. Solar-produced steam is used in the low

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6 Statement of Commissioner William Badger (Maryland Public Utilities Commission) on behalf of the National Association of Regulatory Utility Commissioners on "Oversight of the Public Utility Regulatory Policies Act" before the Subcommittee on Energy Conservation and Power, U.S. House of Representatives, June 11, 1986.

7 "FERC Filings Headed for Records, Trend Is Toward Smaller Installations," *Solar Energy Intelligence Reporter*. July 15, 1986, p. 223.

8 Windfarm Ltd., FERC Docket No. QF 82-80-000, (1982).

end of the dual-inlet generator, while the gas-fired auxiliary boiler supplies steam in the high end.

FERC ruled that while the auxiliary boiler is not a fixed asset, the serial use of steam that passes from the high to the low end of the turbine qualifies the entire system.[9] The MSW facility uses a similar supplementary source of power, a gas turbine. In this case certification was denied. The crucial difference between the two projects, FERC pointed out, is that in the solar thermal system, the supplementary power from the high end of the turbine is used solely to make the low end run more efficiently. On the other hand, the gas turbine in the MSW project is run separately and does not serve to power an otherwise fixed asset. FERC noted that the gas turbine "was merely a device for increasing the capacity of the facility over what could be produced by means of the municipal refuse..."[10] In this case, only the MSW portion of the system qualifies for PURPA benefits.

For the most part, the decision as to what types of systems qualify PURPA rests with FERC. Nonetheless, even though the states have no power to exempt certain facilities from regulation under the Public Utility Holding Company Act and the Federal Power Act, Wisconsin has adjusted the definition of "qualifying facility" for purposes of expanding eligibility for avoided cost buy-back rates. The Wisconsin Public Service Commission has ruled that "all COGS [customer owned generating systems] whether or not they meet the requirements for 'qualifying status' under FERC..should be eligible for avoided cost-based buy-back rates. In addition, old and new COGS alike (i.e., those constructed pre- or post-November 1978) should be entitled to receive payments reflecting avoided costs for all electricity they supply to the utility."[11] This later provision goes beyond FERC rules which state that purchase rates for power from a qualifying facility constructed before November 1978 need not be set at avoided costs. Connecticut applies a different efficiency standard to qualifying facilities, requiring a minimum useful thermal energy output of 20 percent of the total energy output for the facility during any calendar year.[12]

C. Utility Ownership of Qualifying Facilities

As the market for independent, largely unregulated electric power generation expanded, regulated utilities became interested in finding ways to get involved profitably. Qualifying facilities are essentially unregulated, enjoying exemptions from the Public Utility Holding Company Act (PUHCA), most of the provisions of the Federal Power Act, and state laws regarding financial and organizational regulation of electric utilities. Such projects should be less expensive to develop, and hence more profitable. The initial rules promulgated by FERC, however, prohibited electric utilities, electric utility holding companies, and subsidiaries of electric utilities from owning more than a 50 percent equity interest in a qualifying facility.[13] FERC later revised its rules to allow electric utility holding companies or subsidiaries of

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9 Luz Solar Partnership, Ltd., FERC Docket No. QF 84-434, (February 1986).

10 Power Developers, Inc., FERC Docket No. QF 85-504-000, (March 1986).

11 Wisconsin Public Service Commission, Order No. 05-ER-11, 05-ER-12, 05-ER-13, (June 23, 1983).

12 Connecticut Public Act No. 86-403.

13 45 Fed. Reg. 17 March 20, 1980.

holding companies that are exempt under certain sections of PUHCA to own 100 percent of a qualifying facility,[14] and numerous utilities have established subsidiaries that have entered the independent power generation market. It should be noted that there were only 12 utility holding companies registered under PUHCA in 1982.[15]

A utility that becomes involved in a PURPA subsidiary must either limit its equity interest in the subsidiary or limit its equity interest in individual projects to less than 50 percent. The first case provides for a subsidiary to be partially owned (50 percent or less) by the parent utility and to have the subsidiary own and operate each project. The second approach allows the subsidiary to be wholly owned by the utility but the subsidiary must find joint venture partners on a project-by-project basis.

Two important applications before FERC have challenged the utility ownership restrictions of qualifying facilities. In the Ultrapower 3 case, FERC approved qualifying facility status for a partnership arrangement in which a subsidiary of Tucson Electric Company invested two-thirds of the capital in a small power project but limited itself to a 50 percent equity position in its share of any profits and losses.[16] Another applicant, Kidder Peabody Diversified (KPD), was denied QF status for failure to distinguish between "equity" and "control." The KPD proposal would have allowed electric utilities to maintain, on a passive, limited partnership basis, more than a 50 percent equity in QFs. The program was structured to separate investment and financial interest from control in cogeneration and small power projects. FERC noted that "KP Diversified's reliance on the element of control to the exclusion of capital contributions and distribution of profits is improper and that, because utilities participating in the KP program could contribute up to 99 percent of the capital and receive up to 99 percent of the profits, they may have more than 50 percent of the equity interest in qualifying facilities."[17]

Another issue of concern stemming from the federal regulation involved location of qualifying facilities owned by utility subsidiaries. The Securities and Exchange Commission (SEC), which enforces PUHCA, has taken the position that a PURPA subsidiary of a registered holding company can only operate inside the service areas of the operating utilities which are part of the holding company's system.[18] The SEC position is derived from a prohibition in the law against operations that do not form part of an integrated utility system. If upheld, the SEC view may make ownership of PURPA subsidiaries more difficult for registered holding companies when a utility wants its subsidiary to develop projects outside its service territory (in order to avoid self-dealing issues at the state level).

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14 Ross D. Ain, "Business Opportunities for Utilities in Small Power Production and Cogeneration," Edison Electric Institute workshop on Opportunities for Diversification and Cost Savings, Dallas, TX, March 16-17, 1983.

15 Francis J. Andrews, Jr. "Diversification and the Public Utility Holding Company Act," *Public Utilities Fortnightly*. December 23, 1982, p. 25.

16 Ultrapower 3, FERC Docket No. QF-84-121,27, (1984).

17 KP Diversified Investor Inc., FERC Docket No. EL 85-2, Order Denying Declaratory Relief, (July 2, 1985).

18 John W. Pestle and William H. Smith, "PURPA Subsidiaries: Utilities Take on Small Power Production," *Hydro Review*. Spring 1985, pp. 38-41.

Utility ownership issues that concern state regulators revolve around shareholder versus ratepayer interests. These include the treatment of profits and losses resulting from the utility owned, or partially owned, cogeneration or small power project as these affect the regulated rate-of-return of the utility operating company; competition between utility subsidiaries and non-utility projects for limited QF benefits (e.g., capacity credits or transmission capacity); and the impact of non-regulated utility activities on the services it provides to utility ratepayers (e.g., ability to raise capital for new utility construction programs). No uniform treatment of these and other similar issues is evident. The approaches of four states—New York, Connecticut, Michigan, and Wisconsin—illustrate the variety of approaches taken.

In New York, the state legislature has established guidelines on utility formation of subsidiaries specifically for PURPA project development. The law states that "any electric, gas, or steam corporation shall...be authorized to establish, and finance out of retained earnings (unless the commission shall find that such financing may affect the corporation's ability to meet its obligation to provide safe and adequate service at just and reasonable charges to its customers) a subsidiary corporation which shall have as its sole purpose ownership and/or operation of cogeneration, small hydro, or alternative energy production facilities. Any such subsidiary corporation shall be exempt from regulation by the commission...and the commission shall have no authority to regulate any rates, charges, or service terms."[19] Pursuant to the law, Niagara Mohawk and Central Hudson Gas and Electric have formed subsidiaries (Hydra-Co and Central Hudson Cogeneration, respectively).

Connecticut enacted a law denying PURPA benefits to projects that are owned, *in any part*, by utilities or their subsidiaries.[20] United Illuminating Company and its subsidiary, Research Center, challenged the scope of the state statute, claiming that the prohibition was based upon a misinterpretation of the law. Connecticut has recently revised its ruling on utility ownership to allow affiliated entities which "generate(s) electricity in the state solely through the use of cogeneration technology, solely through the use of renewable energy sources, or through both, only at a facility having a generating capacity of not more than three hundred kilowatts and such entity sells such electricity pursuant to a [DPUC] approved contract."[21]

In Michigan a utility can own up to 50 percent of a qualifying facility and the project will be treated on a non-jurisdictional basis or below-the-line. The first such project to which this ruling will be applied is the Consumer Power Company's conversion of the Midland nuclear power plant to a cogeneration facility.[22]

Finally, the Public Service Commission of Wisconsin has prohibited Wisconsin Public Service Company (WPS) from forming subsidiaries to build cogeneration plants that would make sales primarily to end-users, and sell surplus energy at avoided cost rates to WPS. The Commission noted, "In short, WPS will be providing utility service indirectly through its subsidiary. It [WPS] cannot designate one of its generating plants as non-utility property because it services a limited group of customers, or a single customer. It would be a triumph of form over substance to allow a subsidiary to be defined as non-utility, if its sole function were to perform what was

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19 New York Public Service Law, 66-c. Subsection 2 and 3, (1984).

20 Connecticut State Law 16-243 B, cited in *Emerging Issues in PURPA Implementation.* (DOE/PE-70404-H1), U.S. Department of Energy, March 1986, p. 12-2.

21 Connecticut Public Act No. 86-289, pp. 1-2.

22 Michigan Public Service Commission, Order No. U6798.

previously and still is the provision of utility service to a utility customer."[23]

In sum, the states are far from unified in their approach to utility ownership of qualifying facilities. Many state regulators fear the potential of unfair competition with non-utility QFs, and utility attempts to structure projects exclusively to take advantage of the favorable regulatory treatment of QF projects. The implications are mixed for renewable energy. Greater equity participation by utilities would provide additional project capital and could increase market penetration of the renewable energy technologies. However, the greatest interest on the part of utilities appears to be in cogeneration. To the extent that utility investments in cogeneration projects fulfill need for new capacity, renewable energy projects may lose out.

D. Avoided Cost and Buy-Back Rates

The rate paid by utilities to qualifying cogenerators and small power producers for their power (buy-back rates), the first seriously disputed issue in PURPA implementation, remains a critical factor in the process of encouraging renewable energy systems in the utility sector. The Federal Energy Regulatory Commission rules require that buy-back rates shall be equal to the "avoided cost" of the utility. Avoided cost is further defined as the "incremental cost of electric energy, capacity, or both, which, but for the purchase of the QF, such utility would generate itself or purchase from another source."[24] FERC deferred to the state regulatory commissions in establishing specific methodologies for calculating buy-back rates that are "just, reasonable, and in the public interest."

When PURPA was being implemented, policy statements and court decisions at the federal level recognized the long-term value of alternative energy sources relative to near-term costs and provided the basis for encouraging independent power production.

The U.S. Congress:

> "The Commission [FERC] and States may look beyond the cost of alternative sources which are instantaneously available to the utility and the costs savings to the utility which may result at some later date by reason of supply to the utility at the time of purchase from the cogenerator or small power.producer."[25]

The U.S. Supreme Court:

> "At this early stage in the implementation of PURPA, it was reasonable for the Commission [FERC] to prescribe the maximum rate [full avoided cost] authorized by Congress and thereby provide the maximum incentive for the development of cogeneration and small power production."[26]

The Federal Energy Regulatory Commission:

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23 Wisconsin Public Service Commission, Order No. 6690-DR--100, (April 18, 1985).

24 18 C.F.R. 292.101 (a)(6).

25 Conference Report on the Public Utility Regulatory Policies Act, Report No. 95-1750 (1978).

26 American Paper Institute vs. American Electric Services Corp., 461 U.S. 402, 103 Supreme Court 1921 (1982).

"This Commission [FERC] has set the rate for purchase at a level which it believes appropriate to encourage cogeneration and small power production, as required by Section 210 of PURPA. While the rules prescribed under Section 210 of PURPA are subject to statutory parameters, the states are free, under their own authority to enact laws or regulations providing rates which would result in even greater encouragement of these technologies. However, state laws or regulations which provide rates lower than the federal standards would fail to provide the requisite encouragement of these technologies and must yield to federal law....If a state program were to provide...a rate higher than that provided by these [FERC] rules, the QF might seek to obtain the benefits of that state program. In such a case, however, the higher rates would be based on state authority to establish such rates, and not on the Commission's [FERC] rules."[27]

The setting of buy-back rates has become an evolutionary process whereby, with some minimum criteria established at the federal level, state commissions use their authority to meet state policy objectives. FERC acknowledged that state objectives to encourage cogeneration and small power production might even require establishing greater incentives (specifically higher buy-back rates) than provided in FERC's rules. These objectives include elimination of the need for more central-station plants, the creation of new industries, diversification of supply sources, promotion of certain technologies, or any combination of these. State approaches, which have varied over time even within a single state, range from accepting utility filings to avoided cost rates, to establishing standard rates and/or avoided cost methodologies or competitive bidding for specific increments of capacity. Each approach carries direct or indirect implications for renewable energy systems.

Avoided costs, for example, are divided into two classes: energy costs and capacity costs. Energy costs are determined by short-run variable costs of the utility system. They consist of the cost of buying power from an alternative source, or the cost of the fuel, and variable operation and maintenance costs for running an existing system. Under the FERC requirements, utilities must compute the costs that determine their avoided cost for peak and off-peak periods for five years into the future. These cost increments are calculated at intervals of no more than 100 megawatts of capacity, depending on the size of the system, and are made available to the public and appropriate state regulatory agencies. To date, most state utility commissions have set energy and capacity avoided cost rates for on- and off-peak periods (both daily and seasonal).

Avoided capacity costs are the incremental capital costs of acquiring and maintaining additional generating capacity for the utility system. The capacity can represent either a specific generation system or purchase of firm capacity from another utility. A firm commitment of capacity by a QF is a guarantee that the level of output stated in the contract will be available to the utility. Renewable energy systems able to offer firm capacity should include technologies such as wood and municipal solid waste systems and geothermal power systems. A non-firm commitment, on the other hand, represents an "as available purchase of power from a qualifying facility." In this case, there is no guarantee to the utility that the power will be available at a particular time.

For independent power producers and utilities, the distinction between energy and capacity component of avoided cost is an important one. The inclusion of a capacity credit in buy-back rates makes the QF project more economical because in addition to kilowatt-hours delivered, it receives an annual payment for each kilowatt of capacity for which it receives credit. At the

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27 45 C.F.R. 12,221, February 25, 1980. Cited in *Emerging Policy Issues in PURPA Implementation*. Op. Cit. p. 63.

same time, purchases of firm capacity have a more beneficial effect on utility planning processes and operating strategies.

With respect to intermittent renewable resources, FERC has acknowledged the need to establish avoided capacity credits for "relative firmness" of power availability, noting that: "Utilities can be required to pay capacity payments even if the QF provides electricity only on an 'as available' basis (such as would occur with intermittent resources like wind or solar). In such cases, calculation of the payment would be based on a probabilistic estimate of production of a large number of similar QFs."[28] That is to say, the value of non-dispatchable QF, in the aggregate, may result in firm capacity. In practice, solar and wind systems have demonstrated that they deserve capacity credits in utility power applications, especially where resource availabilities match the utility's load profile.

Some states have implemented FERC's avoided cost guidelines in a passive manner, leaving the utilities to calculate buy-back rates. Other states have used the flexibility in FERC's rules to establish specific buy-back rates and methodologies. A discussion of the methodologies and assumptions for avoided cost calculations are beyond the scope of this report.[29] Instead, we will focus on novel approaches take by state regulators in determining the rate for sale of QF power, and especially on those approaches with particular implications for renewable energy systems.

Iowa and New York established minimum, or floor, buy-back rates, intended to encourage independent power production based on a reasonable determination of a statewide avoided cost for utility generated power. In both states, the buy-back rates were challenged by local utilities contending the floor price exceeded their true avoided cost, and PURPA's intention. In New York, the rate was upheld by the Court of Appeals which noted: "The purpose of both the state and federal [PURPA] statutes are identical; they seek to encourage development of alternative energy production...This court holds that there is no conflict between PURPA's maximum purchase rate and the Public Service Law's higher minimum purchase rate... FERC determined that independent, complimentary state regulation in the field was not supplanted by PURPA but could be used to expand the federal PURPA-based objectives."[30]

In Iowa the case was decided differently. The Iowa Commerce Commission established a minimum buy-back rate of 6.5 cents per kWh calculated on the basis of the avoided cost of a recently completed power plant, not the next plant proposed plant. In setting the rate, the Commission stated that the data concerning the next plant "is so speculative as to be almost meaningless...it appears reasonable to assume that the full avoided cost of each utility will be at least 6.5 cents."[31] Following a petition for judicial review filed by the state's seven public utilities, the Iowa District Court ruled the rate invalid, noting "the fact that our Commission

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28 18 C.F.R. 292.304 (d) (1).

29 See also R. Burns, W. Pollard, T. Prior, and L. Pike. *The Appropriateness and Feasibility of Calculating Avoided Cost.* National Regulatory Research Institute, 1982 and *Cogeneration: Regulation, Economics and Capacity.* Volumes 1 and 2. Energy Information Administration, 1983.

30 Con Edison vs. New York Public Service Commission. New York Court of Appeals,, Case No. 438 (1984).

31 "Iowa's Minimum Buy-Back Rate Is Declared Invalid, Commission Appeals," *PURPA Lines,* May 5, 1986, p. 1.

chose to adopt a statewide rate affecting all public utilities makes it impossible to gauge whether or not a subsidy exists, and if so, whether the same is reasonable."[32] The Commission was held to have exceeded its statutory authority by failing to give due consideration in determining the buy-back rates to factors mandated by the Iowa legislature in rate-setting procedures. The Iowa Commerce Commission has subsequently filed a motion of appeal.

Another interesting approach to regulatory support for independent production is found when state utility commissions attempt to quantify non-economic benefits in their rate making procedure. In Maryland, a hearing examiner rejected utility avoided costs as a rate ceiling, recognizing that a higher rate is in the "interest of Potomac Edison, its customers, QF operators, and the national policy of encouraging QF development...the higher rate [is] needed to encourage QF development and operation."[33] In effect, the hearing examiner was saying that QF development has intrinsic benefits which exceed the directly measurable value of the energy and capacity provided to the utility.

Similarly, the Virginia Corporation Commission ordered a 15 percent surcharge to Virginia Electric Power Company's avoided cost. The Commission order noted that "many factors which make cogeneration and small power production facilities in the public interest are more intangible...and the associated costs which could be avoided are societal and environmental in nature."[34] Finally, the Oklahoma State Corporation Commission required Oklahoma Gas and Electric to pay a municipal solid waste burning QF an "energy conservation payment" to reflect the ecological benefits to society as a whole and certain savings to the citizens of Oklahoma if sanitary landfills are not utilized.[35]

While some states have provided greater than "avoided cost" payment energy and/or capacity, others have developed a competitive bidding scheme to ensure that the lowest possible costs are passed on to consumers. In these cases, the avoided cost becomes a ceiling, not a floor, for setting buy-back rates, and QFs are left to compete with one another for limited capacity credits. In Maine, for example, the PUC has established 50 megawatt decrements for the state's largest utility, Central Maine Power. The maximum rate is set at the utility's bid for that increment of capacity. The bidding process lets the utility decide how to establish priorities for QFs which would presumably incorporate the same types of factors a prudent utility would consider in its own power supply decision: cost, expected reliability, expected on-line date, usefulness of facility during system emergencies, utility's ability to control the dispatch or maintenance of the QF, and the existence of other favorable contract terms.[36]

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32 Ibid., p 2.

33 Maryland Public Service Commission, "Proposed Order of Hearing Examiner in Re: Potomac Edison Company," Case No. 7559, Phase II. Cited in Energy Bureau, Conference on Avoided Costs; Houston, November 30, 1984, pp. 111-112.

34 Virginia Corporation Commission Case No. PUE 830067, November 1985.

35 Oklahoma Corporation Commission, Case No. 29257, November 1984. Cited in *Emerging Policy Issues in PURPA Implementation*. Op Cit. p. 6.22.

36 Maine Public Utilities Commission, Docket No. 84-234(Ma 30, 1985).

Massachusetts has established a competitive bidding approach under which the utility issues a request for proposal (RFP) listing the size of the available supply block and ceiling price schedule.[37] The Department of Public Utilities recently approved a bidding proposal by Boston Edison to provide "adders" for QFs under 40 MW and those that use renewable resources.[38]

Given its limited application to date, it is difficult to determine how renewables will fare under the bidding approach. In one sense, a cost-based competitive process may favor large cogeneration systems relying on inexpensive natural gas. However, with smaller blocks of capacity available under a utility prioritization procedure, a diversified mix of smaller renewable energy systems could prove to be more competitive. In Maine, the first state to use competitive bidding, natural gas supply is limited and the most significant resources in the first supply blocks are wood and hydroelectric. The types of projects to emerge from the competitive bidding approach and the mix of technologies in the different states employing it are likely to vary substantially.

E. Standard Rates and Contracts

In establishing the rules for PURPA implementation, FERC recognized that buy-back rates and contract terms for large independent power producers can be left to negotiations between the QF and the utility. For smaller QFs, however, the costs of contract negotiations may become prohibitive. Consequently, FERC elected to require a standard price that each utility offer for small power producers with generating capacities of 100 kilowatts or less.[39]

A survey of PURPA implementation by *Energy Users News* indicates that most states have adopted the 100 kilowatt (kW) limit for standard rates, while other states have modified this limit. For example, Pennsylvania and the Tennessee Valley Authority raised the limit to 500 kW of capacity. Maryland, Delaware, and New Jersey have established a ceiling of 1 megawatt (MW) for standard buy-back rates. North Carolina has standard rates for QFs of 5 MW or less. Indiana sets the limit at 72,000 kilowatt hours per month.[40]

Some states have attempted to simplify the rate setting procedure for QFs by using a "net billing" approach. Maine and Minnesota, for example, have set buy-back rates for 100-kW and 40-kW projects at the retail rate. Connecticut allows net energy billing for renewable energy small power facilities up to 100 kW and fossil fuel facilities up to 50 kW. In effect, the QF only pays, or is paid, for the difference between kilowatt hours produced and kilowatt hours consumed. This system is particularly appealing to small projects which are intended for self-generation. Since retail rates exceed avoided costs for many utilities, establishing the buy-back rate at the higher retail level could represent a considerable incentive for qualifying independent energy production.

Another means used by some states to assist cogenerators and small producers in their negotiations with the purchasing utility is offering one or series of standard contracts from

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37 Massachusetts Department of Public Utilities, Order No. 84-276-B, Regulations, Section 8.05.

38 Massachusetts Department of Public Utilities Docket No. 86-217.

39 18 C.F.R. 292.304 (c).

40 "Cogeneration Collection," *Energy Users News*, 1986.

which the qualifying facility may choose. The standard contracts can be either short-run or long-run, and include provisions for buy-back rates, back-up service, interconnection requirements, and performance liability payments. For the small power producer, standard contracts help reduce the transaction costs of negotiating individual contracts with the utility while providing greater assurance of long-term revenue to meet financing requirements.

Standard contracts have been recognized by a number of state regulatory commissions as a tool for encouraging cogeneration and small power production on a non-discriminatory basis. Establishing standard contracts also provides a way to consolidate the input of utilities and independent power producers into one proceeding. As of mid-year 1984, 20 states had established a predetermined standard offer contract or contracts for qualifying facilities based on size.[41]

TABLE 1

Size Limits on Requiring Standard Contract Offers

Size Limit (kW)	Number of States*
40	1
100	6
500	1
1000	2
10,000	1
No limit	9

* Note: Total of 45 responses.

Source: Claire Wooster (Washington University, St. Louis), "Summary of State PUC Questionnaires Concerning State Implementation of PURPA," unpublished, 1986.

Most states instituting standard offer contracts include no size limitations. Utilities have argued that a more efficient process and lower costs for ratepayers would result from individual negotiations between a utility and independent power producer (especially larger cogenerators). In defense of standard contracts for all QFs regardless of size, the Nevada Public Service Commission (NPSC) noted that:

> "[A utility's] desire to maintain flexibility in the negotiation process need not be inconsistent with the utilization of a standard offer contract. Use of a standard contract in a purchase power negotiation process does not necessarily prohibit negotiation of certain terms...Indeed, it may be significantly more efficient to negotiate site- and project-specific conditions by using a standard document in which many terms are fixed...The Commission also believes that having a basic contract is critical to the

41 Claire Wooster (Washington University, St. Louis), Summary of State PUC Questionnaire Concerning State Implementation of PURPA, unpublished, 1986.

orderly development of cogeneration and small power production in the state and compliance with PURPA."[42]

It should be noted that contracts in Nevada are developed by the utilities and the NPSC has chosen not to become involved in the details of specific standard contracts.

One provision used in standard contracts that provides great assistance in the financing of independent projects (especially capital-intensive renewable energy projects) is the "levelization" of avoided costs over the life of the contract. Levelization discounts future avoided cost to the present value, establishing a fixed or constant payment over the life of the contract.

In effect, the purchase rate does not follow the actual avoided cost (which is expected to increase over time), but rather is higher than the avoided cost in the near-term and below avoided cost in the later years of the contract. The Iowa Commerce Commission pointed out that "this feature [levelization] more nearly matches the capital requirements of the typical [small power producer] which may well experience the greatest demands for interest and principal in its earliest years."[43] Levelization was developed to make these projects more attractive to investors.

While levelization is common for all technologies in California, it is interesting to note that the New York Public Service Commission has limited the availability of levelized standard contract offerings to hydroelectric facilities alone. The New York Commission reasoned that "non-hydroelectric facilities tend to be vulnerable to the fuel market, such as fossil-fueled cogenerators, relatively unproven technologically or short lived, such as landfills or wind mill units, or largely undeveloped, such as solar power...In view of the nascent stage of development of some of these facilities (and) the uncertainties surrounding the economics of others...we will establish separate standard contracts."[44]

In 1982, the California Public Utilities Commission (CPUC) ordered California utilities to file short-run standard offers which were essentially complete contracts, including prices.[45] These offers were available to all QFs without exception or conditions. In 1983, the CPUC adopted Interim Standard Offer No. 4 (SO4) which fixed energy payments based on a forecast of the short-run energy payments.[46] By late 1984, SO4 had attracted so many QF proposals that, if all had been developed, the abundance of QF capacity would have resulted in a displacement of nuclear, geothermal, and economy energy (from the Pacific Northwest), a development not predicted in the initial calculation of avoided costs. In addition, the drop in oil and natural gas prices upon which the energy payments were forecast added pressure on the CPUC to suspend SO4 until a new standard contract could be developed. The CPUC has since issued a

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42 Nevada Public Service Commission, Docket Nos. 85-112, 142, 318, and 325.

43 Iowa Commerce Commission, Order Adopting Rules, July 27, 1984. Cited in Neil Hamilton and Carol Bros, "The Need for Standard Contracts for Small Power Producers," *Public Utilities Fortnightly*. May 30, 1985, p. 30.

44 New York Public Service Commission, Case No. 28962 (March 27, 1986), pp 56-59.

45 California Public Utilities Commission, Decision No. 82-01-1-3 (January 21, 1982).

46 California Public Utilities Commission, Decision No. 83-09-054 (September 7, 1983).

revised long-run standard offer that includes a total capacity limitation (based on 12-year resource plans) and a competitive bidding scheme to determine the actual price paid to QFs.[47] Under the new plan, every two years utilities must file an update to the long-run standard offer based on adjustments in their resource plan.

The situation in California demonstrates the evolutionary nature of utility regulation, particularly the adjustments made in PURPA rules and regulations based on experience and changing conditions. The CPUC was one of the first state commissions to adopt standard contracts and felt that a long-term contract with established buy-back rates was necessary to encourage QF development. Following the significant increase in QF development and the changing economics of the energy market in California, the CPUC modified its rules to ensure that any further QF development be consistent with a least-cost approach to securing new capacity. In this environment, it is uncertain whether renewable energy small power production can compete with large gas-fired cogeneration systems, especially under the new standard contract terms.

F. Interconnection Requirements

As mentioned earlier, one of the primary purposes of PURPA was to remove the obstacles that might prevent independent power production facilities from interconnecting with an electric grid. While the utility is obligated to interconnect with a qualifying facility, the additional costs associated with accommodating the qualifying facility into the grid must be borne by the QF. In its final rules, FERC prescribed the following interconnection guidelines for state regulatory authorities:

> "Any state regulatory authority (with respect to any electric utility over which it has ratemaking authority) or non-regulated utility may establish reasonable standards to ensure system safety and reliability of interconnected operations. Such standards may be recommended by any electric utility, any cogenerator or small power producer, or any person. If a state regulatory authority...establishes such standards, it shall specify the need for such standards on the basis of system safety and reliability."[48]

FERC later added:

> "Each qualifying facility shall be obligated to pay interconnection costs which the state regulatory authority...may assess against the cogenerator or small power producer on a non-discriminatory basis with respect to other customers with similar

47 California Public Utilities Commission, Decision No. 86-07-004 (July 2, 1986).

48 C.F.R. 292.308.

characteristics...Each state regulatory authority...shall determine payments of interconnection costs, which may include reimbursement over a period of time."[49]

The standards set for interconnection are an important concern for electric utilities and independent power producers. Utilities face a novel situation because power sources over which they have no direct control may connect almost anywhere on their systems, from transmission lines down to low-voltage distribution networks. The utilities have massive investments in transmission and distribution systems that were never designed with this in mind, and thus have had numerous and legitimate concerns about the effects of independent power systems on utility system performance, equipment, and safety.

Cogenerators and small power producers face serious problems as well. Complex equipment requirements concerning issues such as metering and power quality (voltage regulation, harmonics, synchronization, power factor, switches, relays) can make any project uneconomical, particularly smaller ones. Large indemnification requirements (e.g., liability insurance) can have the same effect. In addition, QF developers are concerned about protection of their equipment from utility-forced outages or other variations in utility operations.

State utility commissions must balance these interests as they adopt policies affecting interconnection with regulated utilities. A 1981 survey of state utility commission interconnection rules noted the following: "The commissions with proposed rules or adopted rules have taken diverse approaches, but the formal results nevertheless are quite similar. Rarely are interconnection standards prescribed in detail, except by reference to electric codes like the National Safety Code. Instead, small power producers are required to meet equipment and operating standards set by the interconnected utility."[50] A more recent survey indicated that only nine state commissions (20% of the respondents) have established a method to calculate and collect interconnection costs. "Since, however, the equipment required can be highly case specific and open to considerable technical debate, most commissions appear to have left the determination of appropriate interconnection equipment to the utility or utility cogenerator."[51]

Utility requirements for interconnection range from simple to complex. Most utilities include a list of requirements on relay protection, automatic reclosure modifications, synchronous generators, induction generators, and inverters. Voltage and frequency relays must be installed in order to trip the independent generator if problems are detected in the utility system, or when the independent generator is isolated from the system. Southern California Edison Company (SCE), however, has recognized that it can distinguish those cases where a generator could supply the load of other customers on its circuit during fault clearing or maintenance operations.[52] In such cases where an independent generator, isolated from the system, can still supply loads, the independent generator has to have undervoltage and overvoltage,

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49 18 C.F.R. 292.306 (a) and (b).

50 *Interconnection Standards for Small Power Producers: A Survey of State Utility Commissions and Selected Utility Companies*. National Conference of State Legislatures for U.S. Department of Energy, 1981, p. 5.

51 Claire Wooster, Op. Cit.

52 Robert W. Beckwith, "Interconnection: Design and Protection Requirements," *Hydro Review*. Spring 1985, p. 75.

underfrequency and overfrequency, and phase sequence relays to ensure that the supply will remain within specified limits.

As utilities have gained more experience with the impact of non-utility generators on their systems, and regulators have intervened on behalf of qualifying facilities, many utilities have standardized their interconnection requirements in the form of published guidelines. Guidelines approved by the public utilities commissions typically require data and drawings on the type of generator and power conditioning and anticipated independent power producer loads. Typically, utilities have fewer and less stringent protective functional requirements for the smaller generators, i.e., generators less than 20 kilowatts have fewer functional requirements than generators larger than 100 kW.[53]

The cost of interconnection continues to present difficulties for smaller projects, according to the New York State Energy Research and Development Authority. Economies of scale figure in the problem, given that interconnection costs for a one-kilowatt photovoltaic system under the high protection case established by a New York utility would add 10 cents per kWh to the break-even price. Meanwhile, the costs for a 60-kW induction cogeneration system would add 0.5 cents per kWh, and the costs for a 750-kW synchronous hydroelectric system adds only 0.2 cents per kWh to the break-even price.[54] No easy resolution of the issue of scale economies has been identified; however state regulatory commissions may choose to approve standard interconnection costs for smaller projects to make sure that the projects will be financeable. If the smaller projects are seen to be in the best interests of the public, the regulators may well feel that a subsidy is justified.

G. Transmission Availability and System Upgrades

Another issue in the context of interconnection concern is the need to upgrade transmission capacity to accommodate additional loads attributable to QFs. Upgrading issues relate to the cumulative effect of QF generating capacity on a utility transmission system. Although this problem was not foreseen when PURPA was drafted, experience has shown that interconnecting large quantities of independently produced power to existing electric utility transmission systems can become a barrier to further development. It may even become an issue in the case of single, large capacity projects.

Transmission lines are intended to move bulk power from power plants to population centers. Increasingly, these lines are being used for other purposes as well: to permit sharing of surplus generating capacity between utility systems; to transmit large blocks of low-cost power (also known as "economy energy") between remote states and regions; and to provide emergency reserves in the event of outages. Existing transmission capacity, to some extent, is also intended to provide a margin for increased energy demand in the future, a margin for which present customers already pay in electric rates.

In recent years margins of reserve transmission capacity have been narrowed as utilities take more advantage of growing opportunities for economy exchanges of power. The North American Electric Reliability Council (NERC) reports, for example, that the most limited bulk transmission facilities exist in the Mid-Atlantic region of Pennsylvania, New Jersey,

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53 *New Electric Power Technologies: Problems and Prospects for the 1990s*. Office of Technology Assessment, U.S. Congress, July 1986, p. 171.

54 *A Guide to Interconnection Requirements in New York State*. New York State Energy Research and Development Authority, Report No. 85-2, August 1985, pp. 7-9 and 7-10.

Maryland, Delaware, and the District of Columbia. They have been loaded at 97 percent of capacity for the last several years.[55] In 1984, the Pacific Intertie, part of the 11-state transmission network west of Texas and the Rocky Mountains, was operated at 92 percent of maximum capability.[56] In those areas where limits were being reached, available transmission capacity is likely to become a major constraining factor for QF development. State utility commissions will be faced with new issues now to allocate the costs for upgrading transmission systems in light of non-utility demand for the capacity.

The California PUC dealt with this issue in Northern California when both Pacific Gas and Electric Company (PG&E) and small power producers reported to the California Public Utilities Commission that limited electric transmission capacity threatened to severely restrict development of QFs in the northern half of PG&E's service territory. According to PG&E, limited transmission capacity exists both on lines serving local areas, and on the Pacific Intertie which interconnects PG&E customers with generation sources in the Pacific Northwest, Northern California hydroelectric plants, and the Geysers geothermal plants. The Commission ordered an investigation to explore the extent of the problem and to determine how much it would cost to improve the transmission system to accommodate the independent power sources. The investigation was also intended to determine who should pay for system improvements - owners of small power production facilities or utility ratepayers. In a press release addressing the issue, the CPUC noted:

> "Current PUC policy on how to allocate transmission costs is based on Federal Energy Regulatory Commission (FERC) rules that implemented the Public Utility Regulatory Policies Act (PURPA) of 1978...Under PURPA rules, electric transmission costs for small power producers may be calculated and assigned to the degree the costs exceed those an electric utility would bear if it had not engaged in transmission operations with small power producers, but instead had generated an equivalent amount of electric energy itself, or had bought an equal amount of energy from other sources. Any cost-allocation method the PUC arrives at must conform to the FERC rules."[57]

The CPUC investigation decided that transmission facilities that had system-wide benefits should be paid for by the ratepayers unless the benefits did not justify the costs. On the other hand, facilities that are beneficial only to QFs should be paid for by the QFs.[58] In its interim report, the California PUC noted:

> "[We] continue to support the development of QF power in California in accordance with established law and policies. For this reason, the Commission finds the the

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55 Taylor Moore (Electric Power Research Institute), "Network Access and the Future of Power Transmission," *EPRI Journal*. April/ May 1985, p. 9.

56 Ibid. p. 9.

57 Press release of the California Public Utilities Commission, April 18, 1984.

58 California Public Utilities Commission, Decision No. 85-09-058 Cited in J.E. Ajello and D.I. Fellman (California Public Utilities Commission), "The Development of Alternative Generation in California," Productivity Through Energy Innovation. *Proceedings of the 1986 Great PG&E Energy Expo*, Oakland, CA, April 30 - May 2, 1986, p. 619.

benefits of QF power warrant the sharing of risk by the ratepayer for the costs incurred [by PG&E] due to its interim solution."[59]

The "interim solution" refers to an agreement negotiated among representatives for independent energy producers and the CPUC staff. While awaiting a final CPUC decision, PG&E identified a list of transmission projects, which, when completed over a five-year period, would accommodate an additional 1,150 MW of QF capacity. The Commission agreed to allow PG&E to interconnect QFs before completion of its transmission upgrades even though the utility might be required to back down its own generation at times to accommodate the QF's power.[60]

The additional capacity made available under the interim solution was subscribed within six weeks. There was some doubt, however, as to whether all the QFs that entered into contracts at the time were, in fact, "viable." In an attempt to ensure that available transmission capacity would be fully utilized and to discourage speculation, the negotiators developed an Interconnection Priority Procedure (IPP), later renamed the QF Milestone Procedure.[61] Milestones required QFs to include a project description; proof of site control; payments of a $5 per kW project fee in escrow as earnest money; filing of critical path permits; and meeting deadlines imposed by the project development schedule.[62] The QF Milestone requirements have now been incorporated into the standard offer contracts.

Given transmission capacity limitations in other regions and expected growth of QF development, other states were likely to visit the issue of limited access and distribution of upgrade costs. In large part, utility commissions must determine whether the expansion of transmission capacity is to the benefit of QFs or ratepayers or both. The approach taken by the CPUC was one of negotiation and compromise, but it would not have been possible without its clearly established policy of encouraging cogeneration and small power production.

H. Back-Up Rates and Service

The factors surrounding sale of back-up electricity by utilities to QFs are detailed and complex. Micro issues involve the specific rates a utility can charge for back-up service. In addition, some macro issues have emerged, especially after a FERC decision in the Alcon case (discussed below), that involve the question of utility obligation to supply back-up power to certain facilities. It should be noted that issues regarding back-up rates and service pertain more to cogeneration or self-generation of small power production projects than they do to renewable energy systems designed solely for sales to utilities, such as windfarms. PURPA requires utilities to provide back-up service to qualifying facilities at rates that are "just and reasonable and in the public interest" and do not "discriminate against any qualifying facility in comparison to rates for sales to other customers served by the utility."[63] In its rules, FERC went on to stipulate:

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59 California Public Utilities Commission, OII 84-04-077, Stipulation and Order (July 31, 1984).

60 J.E. Ajello and D.I. Fellman, Op. Cit. p. 619.

61 California Public Utilities Commission, Decision No. 85-01-038.

62 J.E. Ajello and D.I. Fellman, Op. Cit. p. 620.

63 18 C.F.R. 292.305 (a) 1980.

1) Each utility must, upon request of a qualifying facility, provide supplementary, back-up, maintenance, or interruptible power, unless it can demonstrate that offering such services will impair the electric utility's ability to serve its customers, or place an undue burden.

2) The rate for sales of back-up power or maintenance power shall not be based upon the assumption that forced outages of the qualifying facilities will occur simultaneously or during the system peak, and shall take into account the extent to which scheduled outages can be incorporated with the utility.[64]

Supplementary power is the power supplied by a utility to a qualifying facility regularly used by the QF, over and above the power produced by the QF. In other words, a 10-MW facility that consumes 16 MW of capacity on a regular basis would require 6 MW of supplementary capacity from the utility. Maintenance power is power supplied by a utility during scheduled outages of the QF. Because supplementary and maintenance power needs are, or could be, scheduled, the utility should know how much power to plan for and when to make that power available to the QF.

Most state commissions have ruled that utilities should make this power available to the QF under appropriate retail rates or general service tariffs. A review of recent state regulatory decisions by the Arizona Corporation Commission did not reveal any significant trends in the designing of special supplementary power rates.[65]

The Public Utilities Commission of Texas has ruled that "rates for sale of back-up and maintenance power shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities."[66]

As defined by FERC, standby power (a separate form of back-up power) is the electrical energy or capacity supplied by an electric utility to replace QF self-generation during an unscheduled outage. The rates for standby service must include a demand charge to account for the utility's need to maintain reserve capacity to fulfill the QF's unexpected power requirements. But, as mentioned earlier, the demand charge for QFs must not assume that all forced outages will occur simultaneously with the utility's peak load.

The degree to which rates vary from a full demand charge are sometimes called ratchets (a 100 percent ratchet assumes full demand charge). Under the 100 percent ratchet standby rates, the QF pays the standard demand charge for each kW of capacity for which it is requesting back-up service. In some cases this means 100% of the highest demand during the previous 12 months. The Wisconsin Public Service Commission has indicated that factors influencing the demand component of a reasonable standby rate should include the number of standby customers, coincidence of stand-by loads and system loads, and cogeneration technology and reliability.[67]

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64 18 C.F.R. 292.305 (c) 1980.

65 *Cogeneration: Economic and Institutional Trends.* Arizona Corporation Commission, Utilities Division, June 1986, p. 25.

66 Public Utilities Commission of Texas Substantive Rule 23.66(j).

67 54 PUR 4th, 399. *Cited in Cogeneration: Economic and Institutional Trends.*, Op. Cit. p. 25.

Without a history of standby service, establishing the level of standby charges for capacity has proven difficult. As QF penetration increases and utilities and regulators become more accustomed to incorporating QF power needs in system planning, it should be easier to tailor standby rates to the particular resource or technology employed by the QF.

Another major issue in the provision of standby power has resulted from a FERC ruling on a third-party owned cogeneration facility. On August 14, 1985, FERC issued an order [Alcon (Puerto Rico) Inc.] finding that Alcon, a pharmaceutical company and end-user of third-party cogenerated energy, was not entitled to receive standby power from the Puerto Rico Electric Power Authority (PREPA). FERC concluded:

> "Alcon neither owns, nor operates, the QF (qualifying facility). Therefore, we [FERC] concluded that O'Brien (the third party), rather than Alcon, is entitled to purchase back-up power from PREPA and resell such power to Alcon, we believe that it would be an electric utility...and would cease to be a qualifying cogeneration facility."[68]

Commissioner Charles Stalon dissented strongly from the decision, pointing out that approximately 60 percent of all cogeneration projects involve third-party financing. He noted that FERC's decision "preludes cogeneration development projects that involve separate corporate ownership of the production and consumption functions...from asserting the right to back-up power...the most fundamental cornerstone of the [PURPA] Section 210 scheme."[69] The Commission subsequently ordered this case to be reheard. It was, and the decision was reversed in January 1987.[70]

Several states have reacted to the issue raised in the Alcon decision, attempting to insulate third-party cogeneration facilities from this ruling. For example, in the New Jersey Energy Master Plan, the Department of Energy stated that "there is a simple way to avoid the harsh and restrictive nature of the Alcon case. State regulatory officials can order utilities under state law to provide full back-up, supplemental, and maintenance power at affordable rates to third-party cogeneration facilities...Utilities in New Jersey must provide such nondiscriminatory service at fair rates to all cogeneration facilities, regardless of who in fact owns title to the hardware or operates the equipment."[71]

Similarly, the Pennsylvania Public Utilities Commission (PPUC) ordered the state's utilities to provide back-up service to customers of cogeneration plants.[72] In a case before the PPUC, the Cruiser-Chester Medical Center had planned to consume all the steam and electricity of a pending cogeneration project developed by a third-party. Despite the utility's contention that the medical center is now a customer of another provider, the PPUC has ruled that Philadelphia Electric Company (PECO) must provide back-up service to the medical center, even though it is not a QF owner. However, in a later ruling, the PPUC ordered developers in PECO territory to pay a $3.35 per kilowatt per month standby back-up charge, in excess of what

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68 Alcon, Inc., FERC Docket No. QF-84-147 (August 19, 1985).

69 *Emerging Issues in PURPA Implementation*. Op. Cit. pp. 12-19 - 12.20.

70 Energy Daily, January 16, 1987, p. 1

71 New Jersey Energy Master Plan. Op. Cit. p. 102.

72 "Penn. PUC Orders Back-Up to Cogen Customers," *PURPA Lines*. Jul 21, 1986, p. 3.

they pay per kilowatt for the energy they buy. Even if a developer normally does not buy any power from the utility, he still has to pay the service charge. In Michigan, the state's two largest utilities have said that they will provide standby power to third-party owned and operated cogeneration plants despite FERC's Alcon ruling.[73]

On the other hand, several commissions sided with the initial FERC Alcon ruling limiting back-up service to owners of cogeneration systems. It is uncertain how these commissions will approach the FERC's reversal.[74]

Again, back-up service is a primary concern to cogenerators and small power production facilities that are designed to meet on-site energy needs or are sited at a power consuming operation. Renewable energy projects, such as agricultural waste systems on farms or wood waste generation in the forest products industry, must pay particular attention to back-up service issues such as those raised by the Alcon decision and state requirements pursuant to this decision. On the other hand, small power projects intended solely for wholesale power sales are less concerned with back-up service and more focused on utility's buy-back rates. They cannot completely ignore back-up service though, if a service charge is required (e.g., the service charge in the PECO territory could add over $400,000 to the annual operating costs of a 10-megawatt facility) .

I. Wheeling Qualifying Facility Power

Wheeling power from a QF involves the sale or transfer of power to another entity other than the utility in whose service area the QF is located. It can occur in any of three ways: sale to another utility, sale to an affiliated party (self-wheeling), or sale to a retail customer.

Utilities and independent power producers once again find themselves on opposite sides of the issue. For utilities, voluntary wheeling has been practiced for decades between consenting utilities and in many cases has resulted in greater system efficiency and reduced costs to ratepayers (e.g., power pools and economy energy brokerages). Allowing customers to purchase power off-system from QFs would weaken the utility planning process and make it difficult for the utility to determine the need to construct new generating facilities. From the QF perspective, however, greater access to utility transmission lines through mandatory wheeling would promote competition among power suppliers and widen the potential markets for the QF's output.

FERC regulations implementing PURPA stipulate that qualifying facilities should be able to sell their output to other utilities through fair access to wheeling services. Specifically, if the QF power has been voluntarily wheeled, then the purchase obligation would transfer to the remote utility as if it were purchasing the power directly from the QF.[75] However, under this existing voluntary wheeling arrangement, a local utility that is physically interconnected to the independent power plant has monopsony power over the purchase of a QF's output.

A regulator might well consider transactions under the arrangement to be a serious inhibition to statewide QF development, especially when the greatest potential for QF development exists

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73 "Michigan: Grappling With the Alcon Implications," *PURPA Lines*. July 7, 1986, pp. 2-3.

74 "FERC: Third-Party Cogen is Entitled to Back-Up Electricity", Energy User News. 119-87, p.1.

75 18 C.F.R. Section 292.303 (a) and (d).

in the service area of a utility which does not then need the extra power. The concern would arise if other utilities in the state required additional capacity, and if QF development were restricted in those areas by a lack of inexpensive fuels for cogeneration or adequate renewable resources. Some states have faced this problem and, absent federally mandated wheeling requirements have established regulations requiring utilities to wheel QF power.[76] Other states have resisted requests that utilities wheel QF power.

In its initial setting of PURPA requirements, Florida required that utilities wheel QF power.[77] Florida further revised its rules in 1984 to establish a statewide avoided cost rate, an interim wheeling rate of 1 mill/kWh, and a strong suggestion that wheeling charges should be waived where sufficient transmission capability is available and no additional costs would be incurred in providing wheeling services for the QF.[78] Later that year, the Florida Public Utilities Commission (FPUC) and the Florida utilities sought a declaratory order to determine whether wheeling rates were subject to FERC jurisdiction and whether the jurisdiction could be waived or delegated to state commissions. FERC ruled that it had exclusive authority in the setting of rates for transmission of power "in interstate commerce." The Commission did not specifically decide whether it would accept the FPUC's wheeling rate, but noted that under existing precedents, it would "give weight" to the rate determination of a state commission as long as it does not violate FERC rules and policies.[79] The FERC decision did not resolve the issue of whether states could require wheeling under their own authority.

Texas has established mandatory wheeling, primarily in response to a high concentration of QF development in Houston Lighting and Power Company's service area (exceeding what HLP needs for the near term) and plans by other utilities in the state to add generating capacity via central-station coal-fired power plants. Under existing rules, utilities must wheel power to another utility at the request of the QF. The ruling could lead to greater statewide wheeling of inexpensive gas-fired cogeneration from the HLP service area and reduce or postpone the need for constructing new power plants. In Texas, an electric utility must transmit energy and/or capacity from a QF to any other electric utility designated by the QF, provided that such a transmission is not in violation of federal law or other jurisdictional authority. The utility is compensated at a rate that is determined by informal negotiation between Commission staff, utilities, independent power producers, and other interested parties and codified in a Commission substantive rule.[80]

For the most part, the wheeling rates in Texas are outside the reach of FERC authority because 80 percent of the State's electric generation is within the Electric Reliability Council of Texas

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76 For a comprehensive survey of state wheeling requirements see: Adam Wenner, "Wheeling for Cogeneration and Small Power Production Facilities," presented at the Energy Bureau Conference on Wheeling, October 24-25, 1984.

77 F.S.A. Section 366.055; Florida Docket 820,406-EU, Order Nos. 12443 and 12634.

78 Florida Public Service Commission, Order No. 13,247, Docket No. 830,377-EU, May 1, 1984.

79 Federal Energy Regulatory Commission Declaratory Order in Docket No. EL-84-27 et al., FERC Section 61,140 (1984).

80 Public Utilities Commission of Texas, Substantive Rule, Section 23.66(d)(4) &(5).

(ERCOT) region.[81] ERCOT has no jurisdictional control—it does not come under the rate-setting authority of FERC because no synchronous interconnection exists with utilities in other states. Consequently, a Texas utility does not have to wheel QF power if doing so would cause it to become subject to FERC jurisdiction.

The Indiana Public Service Commission has ruled terms and conditions for wheeling of non-firm QF capacity ("as available" supply sources such as wind or solar) are to be specified by contract and "shall not be in conflict with [FERC's] implementation of the Federal Power Act or with any other relevant federal authority."[82] In Indiana, wheeling rates for non-firm capacity are based on the utility's actual expenses (the estimated average cost of the existing transmission-distribution facilities used to provide the wheeling service) plus no more than 2 mills/kWh of electricity wheeled.

In the West, two states have accepted voluntary wheeling by electric utilities for renewable energy projects. Montana Power Company has tentatively agreed to purchase 20 MW of wind-generated energy from a Wyoming QF located 300 miles from its service area.[83] The power is to be wheeled over Western Area Power Administration lines. Utah Power and Light has signed a contract to wheel up to 10 MW of generating capacity from an independent geothermal project to the Provo City, Utah, municipal utility.[84]

Another form of wheeling—self-service wheeling—involves the transmission of power from a QF to an affiliated party. For a cogeneration facility this may mean producing power at one industrial plant and using the utility lines to transmit it to other facilities owned by the cogenerator. A somewhat different self-service wheeling arrangement may be necessary for remote projects such as windfarms, small scale hydro, or geothermal systems, where the resource is distant from the load. Several states have established provisions to cover this situation.

In the New Jersey Master Energy Plan, the Department of Energy included a recommendation to the Board of Public Utilities (BPU) that, "Upon request, each cogeneration facility shall be entitled to transmit its power generation or any portion thereof to and among its customers on a non-discriminatory basis at a rate to be determined by the BPU."[85] Although the New Jersey DOE language only addresses cogeneration, it may also apply to renewable energy small power projects.

The California Public Utilities Commission may authorize a QF to interconnect to a utility distribution system and have the power wheeled to another location "for its own use" if the Commission finds that no uncompensated burden will be placed on the utility and the wheeling

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81 *Emerging Issues in PURPA Implementation*, Op. Cit. pp. 8.16 - 8.17.

82 Indiana Public Service Commission Final Rules, Case No. 37494.

83 *Cogeneration Report*, August 16, 1985, pp. 11-12.

84 *Cogeneration Report*, March 15, 1985, pp. 11-12.

85 New Jersey Energy Master Plan. Op Cit. p. 111.

service will not cause added cost or adverse consequences for its customers.[86] This regulation has not yet been treated by the CPUC, since no requests for such self-service wheeling have yet been submitted.

Extending the concept of wheeling QF electricity further to include retail sales of independently produced power could revolutionize the structure of the utility industry. The concept of an unregulated QF selling power on the market to retail customers threatens the monopoly power that utilities have traditionally held over the sale of electric energy within a given area. Since state utility commissions have the authority to set or approve retail rates, state regulators can also authorize retail sales by parties other than regulated electric utilities as a means of further encouraging independent power production. The approach to this issue has varied across the country.

In New Hampshire, under the Limited Electric Producers Act, the PUC is authorized to review and approve any contract between a qualifying facility and a non-utility retail purchaser.[87] On the other hand, in New Mexico, the PUC considered and rejected a petitioner's request for authorization to wheel wind-generated electricity to residential and light commercial customers.

The Texas PUC has adopted a certification process allowing QFs to engage in retail sales. Regulatory approval is not required if the purchaser or end-user is also the sole purchaser of the thermal output of a cogeneration facility, or if the QF generates less than 10 MW of power *and* 75 percent or more of the energy input comes from renewable energy sources, biomass, solid waste, or a combination of those fuels.[88] Here the PUC has recognized the natural limitation to renewable energy development imposed by an abundant and inexpensive supply of gas-fired cogenerated electricity. By opening up the market for retail sales without PUC approval, small renewable energy systems may be developed that otherwise might not have been had they been forced to compete with natural gas-fired cogeneration on the wholesale market.

J. Performance Requirements and Security Payments

A major issue for the utility industry and state regulators is how to deal with non-performance of QFs and how to determine the liability of a QF that does not meet performance levels stipulated in the power purchase contract. Technical problems, such as reduced system performance or excessive downtime, can prevent a project from performing up to expectations. To the extent that a utility has determined a capacity value of the QF project in its resource plan, failure to perform will have detrimental effects on the overall system—perhaps forcing more expensive projects to be brought on line. Economic problems also arise when expenses are greater than expected or lower performance forces the cost of delivered QF energy to exceed the contracted buy-back rate. In either case, one might reasonably expect the issue to be addressed

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86 California Public Utilities Code, Section 2812.5 Cited in *Emerging Issues in PURPA Implementation*. Op. Cit. 8.10.

87 New Hampshire Rev. Stat. Ann. Section 362-A et seq. Supp. (1982). Cited in Sarah P. Voll, "Forecasting Electric Power Production from Renewable Energy Resources," Op. Cit., p. 29.

88 Personal communication, Kent Saathoff, Public Utilities Commission of Texas, September 11, 1986. Senate bill number 143, now before the Texas Legislature, will amend the Public Utility Regulatory Act to make this a state law.

by liability or security clauses in the contract; in some cases state commissions have intervened in contract negotiations between a QF utility over non-performance considerations.

State utility commissions have intervened in contract negotiations between a QF and a utility over performance requirements. State commissions tend to become concerned when the terms of a contract between an QF and a utility provides buy-back rates in excess of "avoided cost" initially, and payments below "avoided cost" in later years. From the perspective of the state regulator, the ratepayers have provided a loan to the QF that will only be repaid if the contract is fully executed. Failure to perform over the entire contract term can be seen as a default on the ratepayer's loan. Another potential regulatory concern is whether utility stipulated non-performance liability requirements inhibit the development of cogeneration and small power production under PURPA.

One such case occurred in Montana, where the Public Service Commission was asked to issue a declaratory order ruling in a case where the Montana Power Company had sought to include stringent security terms in its contract with a 10-15 MW cogenerating ethanol plant.[89] The utility wanted to require the QF to accept one of four sets of terms: 1) setting aside part of the avoided cost payments in escrow; 2) putting up a letter of credit or surety bond; 3) taking out project failure insurance; or 4) providing a corporate guarantee; or 5) proposing another form of security acceptable to the utility company. The QF has replied that the first four security options are "absolutely unavailable at reasonable cost." The project developer then proposed that the utility act as a lien-holder for the facility.

The Commission's ruling was intended to determine whether the QF proposal, which was unacceptable to the utility, would be adequate. The Commission ruled against the QF, but left the terms of subsequent security proposals up to negotiations between the QF and the utility. The two parties have since signed a power purchase contract that includes acceptable security terms.

A commission can also include security requirements in its long-term standard contracts between a utility and a QF, to ensure protection of ratepayer interests. For example, levelized rates require inflation assumptions that may not be accurate in the long-run. In addition, by allowing overpayment in the first years of a contract, levelized costs create a situation in which the utility may be forced, in effect, to loan funds to the QF. In such a case, some form of security must be provided to offset the risk that this loan will not be repaid.

Security payments may also be required of QF projects receiving capacity payments. The utility and ratepayers may be left with diminished reliability if utility capacity is not added as a result of reliance on QFs which, for one reason or another, fail to perform. Projects with high variable costs (fuel and maintenance) may be more expensive to operate and the developer may decide that it is uneconomic to generate. The same may be true of replacement costs for new technologies that do not last throughout the life of the firm capacity contract.

In developing a competitive bidding scheme in Massachusetts, the Department of Public Utilities (DPU) dealt with this issue by requiring a security deposit by the QF if payments to the QF are expected to exceed those under a ceiling price schedule (such as a levelized payment schedule). At a minimum, the utility must act as a lienholder for the facility. All QFs must deposit $15 per kW of generating capacity, a letter of credit, or other forms of payment acceptable to both parties, which will be returned if the QF meets the scheduled in-service date. In issuing the final rules, the DPU stated that "the Department believes that the ranking formula adopted by the utility should recognize trade-offs in net ratepayer benefits

89 *Electric Utility Week*. July 29, 1985, pp. 15-16.

between risk and security and allow qualifying facilities to provide additional security in order to receive a higher ranking."[90] Utilities may add additional performance requirements if the QF is to be operated under conditions that require dispatchability.

III. RENEWABLE ENERGY AND TRADITIONAL UTILITY REGULATION

Much of the interest in renewable energy has resulted from the success of small power production development and the failure by utilities to develop these resources without specific direction from state regulators. The small scale and shorter construction lead time for many systems using renewable energy technologies reduce the risk of the overcapacity situations and cost overruns associated with projects requiring long construction lead times. Development of these resources, through financing arranged by independent power producers, under contract with a utility can further reduce the economic risks of adding new generating capacity.

Utilities have also recognized the potential benefits of a diversified resource base that includes renewable energy technologies. Much of their positive experience has been gained through development of hydroelectric resources. Although they were often expensive to construct, these facilities are now among the nation's most economical and reliable power sources. Utilities have also recognized the potential benefits of a diversified resource base that includes renewable energy technologies.

Less mature renewable energy technologies are likely to confront barriers until such systems have been adequately demonstrated to utility decisionmakers. Demonstration can occur through traditional channels of utility research and development or through successful operation of small power production facilities by unregulated entities.

State regulators may find themselves faced with the difficult task of deciding whether future development of these technologies should be conducted by utilities, non-utility parties, or both. In every case, the arguments in support of continued renewable resource development will bring up cost and reliability concerns for ratepayers. Nonetheless, regulators are more frequently treating renewable energy explicitly in the more traditional, non-PURPA, forms of regulation.

A. Resource Planning

Resource planning, once considered to be a matter solely within the utilities' domain, has increasingly become a subject of regulatory intervention. Utilities are responsible for developing a long-range resource plan based on a projected demand for electricity and an optimal mix of supply sources necessary to meet that demand. They must also provide an adequate reserve margin of generating capacity. Resource planning decisions are founded on the utilities' obligation to provide "reliable electric service at the lowest possible costs consistent with financial and regulatory constraints." State regulators serve an oversight function by reviewing a utility's proposed resource plans in order to ensure that the public (ratepayers) receives the service it needs at an acceptable price.

In recent years, resource planning has become more complex and politicized. Concerns over rising retail rates, utility overcommitments to new, large baseload coal and nuclear power plants (many of which have experienced considerable cost overruns), the recognition of conservation and end-use efficiency as legitimate supply options, and the emergence of independently produced power by non-utility parties (including utility customers) have forced state regulators to become more involved in providing direction or, in some cases, even prescribing alternatives to the utilities' proposed resource plans.

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90 Massachusetts Department of Public Utilities, Order No. 84-276-B (August 25, 1986).

Several states now require utilities to look to demand-side management and purchases from independent power producers prior to investing in new generating facilities. Other states have embraced the "least-cost" planning concept as a means of supplying energy through greater efficiency. They require utilities to review all supply- and demand-side options and to rank them in economic terms. These approaches, for the most part, have created a regulatory environment that favors the development of renewable energy technologies.

The California Energy Commission, which is responsible for developing and adopting the long-term electricity supply plan for the state, has been an important motivating force behind the diversification of California's power supply and encouragement of renewables. Following the oil and gas price hikes of the 1970s, California promoted conservation and alternative forms of energy as a means of displacing oil. Explicit policies established by the CEC included: 1) favoring projects that minimized costs for ratepayers; 2) supporting development of a resource-balanced generation system (which implicitly constrains utility usage of oil- and gas-fired generation); and 3) pursuing quantitative goals for preferred resource additions.[91]

In Nevada, the legislature passed the Utility Resource Planning Act to help ensure the "least-cost development of electricity and speed up the utilities' response to changing technologies...(and) require adequate and equal consideration of all conservation and supply measures in order to satisfy a given utility's need at a given time."[92] As a result, Nevada utilities have included geothermal development by qualifying facilities in their roster of near-term supply sources.

Similarly, the New Jersey Department of Energy (DOE) requires utilities to present biennial plans that will be subject to its certification. Utilities must incorporate the maximum economic and achievable levels of energy conservation into their supply mix. The term "energy conservation" expressly includes "alternative technologies," defined as "windmills, small-power production, cogeneration, district heating, and other forms of energy conservation that can attain the more efficient use of energy and/or the use of renewable energy sources."[93]

B. Power Plant Certification

On the basis of continued strong demand growth forecasts, a large number of baseload coal and nuclear power plants were proposed by utilities throughout the U.S. in the 1960s and early 1970s. Many of these plants have subsequently been removed from utility resource plans because of the reduced level of demand. Some of the completed units have resulted in excess reserve margins and significant rate increases for utility customers. Consequently, the decisions by electric utilities to pursue further resource additions are being challenged by some state

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91 "The 1985 California Electricity Report: Affordable Electricity in an Uncertain World," California Energy Commission, May 1985, pp. 6 and 46.

92 Statement of Commissioner Stephen Wiel (Public Service Commission of Nevada) on behalf of the National Association of Regulatory Utility Commissioners on "The Efficient Development and Use of Electric Power," before the Committee on Science and Technology, Subcommittee on Energy Development and Applications, U.S. House of Representatives, March 11, 1985, pp 3-4.

93 R. William Potter (New Jersey Department of Energy), "Promoting Cogeneration Development: State Regulatory Issues and Perspectives—How Do We Get There from Here?" presented at the Energy Technologies Conference, Washington, DC, March 21, 1986.

regulators who are requiring assurances that more publicly acceptable options are not available.

State regulators also have the authority to review utility power plant construction plans. For a utility to invest in a new power production facility it must first receive a "certificate of need" (also known as a certificate of convenience). Regulatory approval recognizes the need for such a facility and provides the utility with some level of assurance that it will be able to recover the costs of the investment through its rate base. In recent years, facilities have been "decertified" (postponed or canceled) if the state utility commission decided that the need for the facility no longer exists, or that a more economical source of supply could be found elsewhere.

All this simply underscores the impact that state regulatory decisions can have on utility construction programs. For a utility to receive approval for a conventional power plant in Wisconsin, the utility must show why part of the supply cannot be met with "alternative, non-depletable (renewable) energy sources, or clean-coal technologies."[94] In Texas, for an electric utility generating unit, the Commission may grant an application only when it finds that purchased power, conservation, and alternative capacity and associated energy sources available at a lower or equal cost to the ratepayers, together with capacity from qualifying facilities with which contracts have been executed, cannot be reasonably expected to be available in sufficient quantity and for sufficient duration to allow the utility to modify its capacity expansion plan so as to allow the utility to provide for deferral or cancellation of the generating unit for which certification is requested.[95] The abundance of gas-fired cogeneration in the Houston Lighting and Power service area has resulted in decertification of the utility's proposed lignite power plant.

A different approach to encourage renewable energy development, has been adopted by the Minnesota Department of Energy and Economic Development (DEED). The Minnesota DEED agreed to provide a "certificate of need" for the Sherco 800 MW coal-fired power plant, provided that Northern States Power Company (NSP) spends up to $60 million on energy conservation and renewable energy programs. A 195 kW windfarm has since been constructed by the utility.[96]

In another aggressive initiative, Minnesota has adopted a statute requiring a "certificate of need" for all power production facilities, whether utility or independently owned, with generating capacities in excess of 80 MW. However, if the facility is larger than 5 MW and oil- or gas-fired (including cogeneration systems), a certificate of need is required.[97] Given the economies of scale of renewable energy technologies and the size limitations under PURPA, the Minnesota regulatory commission hopes to provide a major incentive for the development of both utility and non-utility renewable electric projects. In fact, NSP, the state's largest utility, has plans to build, own, and operate several small biomass-fired facilities.

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94 Wisconsin Public Service Commission, Order No. 05-EP-03 (May 23, 1985), Appendix C, p. 2.

95 Public Utilities Commission of Texas Substantive Rule 23.31(c).

96 John R. Dunlop (Minnesota Department of Energy and Economic Development), "State Initiated Utility Windfarm," presented at the Wind Energy Expo '86 and National Conference, Cambridge, MA, September 1-3, 1986, p. 2.

97 Minnesota Statute 216-B. 243.

C. Cost Recovery

Until recent years, utility submissions to recover power plant construction costs faced little scrutiny by state regulators. Until recent years, when a utility invested in new generating capacity, its managers were virtually assured that such costs would be recoverable through the ratebase. This is no longer the case. For full cost recovery to be granted today, regulators generally conduct a "used and useful" test under which the utility investment is judged by its current value in providing electric service. Utilities are not infrequently restricted to partial cost recovery as a penalty for cost overruns, building of excess generating capacity, and operating plants at reduced capacity factors.

From the utility perspective, full recovery of capital invested in generation through traditional rate-making procedures is preferred to deferred recovery because there is less risk. A utility can argue that large baseload generating facilities are still the most economical way to meet future generation needs and a temporary over-capacity situation is a small price to pay. The utility considers that it is being penalized when only part of its new plant is deemed "used and useful" at the time the facility begins operating and the state utility commission defers recovery of the cost associated with the unused portion of the facility. This situation can strengthen the case for investment in smaller, more modular generating units (such as renewable energy systems) which may better match supply with demand. Such an approach to capacity expansion may be more likely to result in full cost recovery through the ratebase at the time of initial operation.

Two states to address the "used and useful" question have acknowledged the impact that the addition of independent power producers can have on traditional utility-financed generating capacity. In Pennsylvania, the legislature recently passed legislation to remove penalties to utilities for excess capacity related to purchases from cogenerators and small power producers.[98] In other words, state regulators would subtract the capacity provided by non-utility sources in their calculation of utility excess capacity, as they define allowable cost recovery.

New Jersey has gone further in addressing independent power production recovery of utility investments. In the proposed New Jersey Department of Energy Master Plan, qualifying cogenerators and small power producers would be able to remove existing utility owned capacity from the ratebase if the QF power is deemed more cost-effective than the utility owned capacity would be. "In a competitive setting, if 'new' power sources replace the 'old' sources, the latter would be written off (perhaps mothballed, placed under new management, or sold off). If found to be obsolete, the uneconomic units would no longer be 'used and useful' to the public."[99]

"Used and useful" are no longer the sole criteria used by regulators to determine the level of cost recovery of utility investments in new capacity. Concerned with the costs overruns of new generating facilities (particularly nuclear power plants), regulators are increasingly focusing their attention on the prudence of utility management decisions. State regulators now tend to deny full cost recovery of newly completed power plants when they find unacceptable construction cost overruns. These disallowances, often in the hundreds of thousands of dollars, must be passed on to the utility investors, putting the utility shareholder at risk for unacceptable cost overruns. This has a chilling effect upon utility construction programs, and is

98 Pennsylvania Sunset Act, Statute 114 (July 1986).

99 New Jersey Energy Master Plan. Op. Cit. pp. 106-107.

forcing utilities to consider capacity expansion via QF, or other power purchase contracts. At the same time, however, utilities are reluctant to build renewable electric projects because new technologies often incur unforeseen expenses and therefore higher than expected in-service capital costs. Utilities fear that these resulting cost overruns may also be subjected to prudence tests.

PURPA induced independent energy production has demonstrated how fixed power purchase contracts can reduce the economic risk of cost overruns for new technologies and their ratepayers. Agreement to deliver energy at a negotiated price shifts the risk of unexpected cost overruns from the ratepayer to the project investor. In testimony before the U.S. Senate, California PUC President Donald Vial noted:

> "In implementing PURPA, we [CPUC] recognized the value of establishing benchmark prices or what we call avoided costs that a QF could automatically receive....Under this approach, ratepayers reap the benefits of a diversified resource base and the longer run benefits of declining utility avoided costs, and also bear reduced risks in construction cost-overruns and fuel price fluctuation. This approach is not just used for QFs. Increasingly, the CPUC has chosen to review all utility generation projects and conservation budgets using the same benchmark pricing....[The CPUC] has even recently considered avoided cost 'caps' on rate recovery."[100]

D. Research and Development Expenditures

A "Catch-22" situation exists with regard to the near-term costs and long-term benefits of R&D. That is, for new energy technologies for utility companies, regulators and utilities recognize that R&D advances can offer options for lower or stabilized electricity costs in the long run. But, since a portion of research funds come from the ratepayers, utility management is often reluctant to ask for additional charges to ratepayers, especially when rates are rising rapidly. Thus, authorization or approval of utility R&D spending can often encounter greater obstacles from internal management than from state regulators. Commissioner Stalon has noted that, "As the utility industry's need for sound R&D has grown, so has the role of the regulator in determining the level and direction for such research."[101]

State regulatory agencies have long had the ability to approve utility expenses in their rate submissions beyond the narrow definition of providing utility services. Deciding how much and what type of longer range R&D is undertaken is much harder for state regulators than approval of expenses devoted to immediate problems. Calculating the public benefit of cutting reduced use of environmentally unacceptable fuel sources and opening the potential for a long-term renewable, sustainable energy future is more difficult to manage and support, especially when the options present rather expensive near-term costs.

Nationally, it appears utility research is concentrating on immediate problems which meet the objectives of both the utilities and their regulators who like to see near-term benefits for

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100 Statement of President Donald Vial (California Public Utilities Commission), on "Electric Power: Potential for Shortages in the 1990's," before the Committee on Energy and Natural Resources, U.S. Senate, July 23 and 25, 1985, pp. 415-416.

101 Commissioner Charles G. Stalon (Federal Energy Regulatory Commission), "Regulatory Treatment of Research and Development Funding," *Public Utilities Fortnightly*. October 25, 1984, p. 21.

utility customers. The Electric Power Research Institute (EPRI) has reported that in the current environment, utility research priorities have been established in the following order of importance: 1) reducing and controlling the costs of electricity to consumers; 2) maintaining and enhancing electricity markets; 3) minimizing environmental and financial risks; and 4) continuing to build technology options for the future.[102]

The Energy Research Advisory Board of the U.S. Department of Energy has pointed out that "regulators are often unwilling to authorize risky ventures. Furthermore, the benefits of successful risk-taking are unlikely to accrue to the utility, while the penalties of unsuccessful risk-taking are generally borne by its stockholders."[103]

Responding to these and other circumstances that tend to minimize long-term R&D expenditures, the National Association of Regulatory Utility Commissioners passed a resolution supporting additional utility funding for research, particularly through contributions to EPRI.[104] The resolution is based on the recognition that long-term research does not result in immediate benefits, yet is the surest route to reliable electric service at affordable prices in the future.

At the state level, one farsighted utility commission has mandated that a percentage of utility revenues must be spent by the utility on research programs and, if not spent in that way, must be returned to the public.[105] In effect, the commission in New York has ruled that the price of buying electricity must include an assessment for research. Apparently, this approach is considered fair and reasonable, and has eliminated virtually all contests over research expenditures in New York rate cases.

Several other states have shown special support for utility R&D expenditures with specific objectives. North Carolina has established a hybrid organization to help all ratepayers gain maximum advantage from alternative energy. In 1980, the utilities commission and the six major electric utilities established the North Carolina Alternative Energy Corporation to "moderate the rate of growth in electric power demand and defer the need to build expensive new central station power plants."[106] Utility contributions are set as a function of annual electricity sales.

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102 Richard E. Balzhiser, "Industry Issues and the Role of R&D," Electric Power Research Institute, 1985 Annual Report. pp. 6-18.

103 "The Federal Role in Energy Research and Development," A Report of the Energy Research Advisory Board to the United State Department of Energy. DOE/S-0016, February 1983, p. 8.

104 "Resolution Supporting Additional Funding for Research Through EPRI," Floor Resolution No. 10, National Association of Regulatory Utility Commissioners, 97th Annual Convention, New York, NY, 1985.

105 Theodore J. Carlson and Charles E. Rider, "Incentives for Research by Utilities," *Public Utilities Fortnightly*. March 3, 1983, pp. 15-16.

106 The North Carolina Alternative Energy Corporation, 1985 Annual Report. pp. 2-3.

In its 1985 Electricity Report, the California Energy Commission recommended that "the state continue to support the development of emerging technologies...To protect ratepayer interests, support should be limited to: technologies that have 1) demonstrated potential for competitive costs, 2) supply and environmental benefits not offered by available technologies, and 3) interest by utilities and private developers in installing power plants in California based on that technology."[107]

The Wisconsin Public Service Commission has given more explicit support to renewables by directing utilities to aggressively research, develop, and promote renewable technologies. The next set of advance utility plans to be given to the Public Service Commission in 1987 must have cost and potential capacity data for hydropower, wood waste, wind, solid waste, and cogeneration.[108] Wisconsin, and similarly Minnesota, has also required utilities to conduct wind resource assessments in their service areas.

E. Utility Diversification into Non-Regulated Businesses

A state regulatory commission can only regulate operating companies that provide utility service within its jurisdiction. It has no power to control the prices charged by a utility subsidiary company for goods and services, or to control management practices within any the diversified corporate structure that a utility may establish. However, a state commission may use its ratemaking authority to discourage potential abuses that could increase rates charged to customers. For example, regulators consider it their regulatory right to address the relationship between ratepayers and shareholders when a utility is involved in a diversification venture. If diversification activities expose ratepayers to potential risks, regulators want to establish clearly the potential benefits. On the other hand, if ratepayers are to be fully insulated from any risks, shareholders expect their profits from an unregulated activity to be protected from confiscation by the regulatory process.

A 1982 report produced by the NARUC Ad Hoc Committee on Diversification categorized key utility diversification issues as falling into three areas: legal, economic, and financial. Legal issues pertain to regulatory authority and jurisdiction over utilities and their activities, including diversified business activities, and concern the choices of corporate structures and business ventures and how those choices affect the interests of utility management, shareholders, ratepayers and regulators. Economic issues involve the incentives for management in the operation of utilities and their diversified business activities, which brings up questions about the ability of regulators to detect or determine the existence of cross-subsidies; the consequences of diversification for utility services, and impacts of diversified sources of income on a firm's economic and accounting profits. Financial issues focus on the

107 The 1985 Electricity Report. Op. Cit. pp. 144-145.

108 Wisconsin Public Service Commission, Order No. 05-EP-4 (August 8, 1986), pp. 18-19 and 54-55.

implications that diversification will have upon investors' valuation of utility securities and how utility diversification will be financed.

These issues are being raised because there is a trend for utilities to diversify their investment portfolios by moving away from strictly traditional electric service into more lucrative ventures that have little or no relation to power generation. When construction programs wind down and power plant investments enter the ratebase, the current environment for many companies, utilities find themselves with surplus internal cash and need to find alternative investments. Slower demand growth and increasing pressure to hold rates down are motivating utilities to establish holding companies and to diversify into unregulated businesses. Diversification also offers the utility the potential of improving financial performance. [109] Utilities note that the organization of holding companies more distinctly separates regulated and unregulated activities, while consumer advocates say it removes the ability of regulators to review the books and records of competitive businesses. If these diversified ventures are treated separately, there is little doubt that a utility can achieve a greater rate of return for its investors (shareholders) than that which is allowed for the parent operating company.

Utility diversification into renewable energy typically falls into one of three types of business ventures: 1) acquisition of or partnership with a renewable energy manufacturer; 2) renewable energy equipment sales, leasing, or services; and 3) development of cogeneration and small power production facilities. While all three of these ventures can involve a potential for increased utility capitalization and greater market penetration by renewable energy systems, regulators feel they must review any such proposal since it might affect utility service and competition with respect to existing small business and entrepreneurs.

The issues in these three areas are varied. As they affect utility investments in a renewable energy manufacturing companies, the issues could involve the ways in which a venture might be financed, and ways that losses might affect the health of the operating company. Utility equipment sales and services ventures must also be reviewed to ensure that goods and services transferred from an affiliated subsidiary to the operating company are assigned a fair market value, since regulators cannot permit the use of subsidized funds from the regulated sector. In addition, easy access to market information about customer energy use patterns could give a utility subsidiary an important advantage over competitors. Finally, utility development of unregulated cogeneration and small power production projects (under PURPA) raises concerns over the fairness of treatment between utility and non-utility affiliated qualifying facility applications. Since independent power production represents five percent of all utility diversification ventures, regulatory oversight responsibilities in this area are likely to increase.[110]

This section has provided some insight into the treatment of renewable energy in more traditional forms of utility regulation. In some cases, state utility commissions have mandated increased utility activity to support renewable energy development. Incentives to increase the

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109 A study by the Edison Electric Institute found that diversified electric utilities outperformed nondiversified companies during the period 1975-1980 both in terms of price earning and market book ratios. Reference in Jack Butler, "Electric Utility Participation in Qualifying Facilities," Florida Public Service Commission, July 1985, p. 12.

110 See "Current Diversification Activity Status, By Type of Venture," Edison Electric Institute, Rate Regulation Department, 1986.

current level of activities are justified on the basis of protecting ratepayer interests and moderating future increases in retail rates.

IV. CONCLUSIONS

A review of the last ten years reveals a highly charged and complex transition in state utility regulation. Utility managers have become more cautious in their investment patterns, particularly in the case of new generation. State regulators have exercised greater authority in the oversight of utility decisionmaking. New sources of supply—especially cogeneration, renewable energy, and conservation—have received increasing attention, and are generally considered to be in the "public interest." Finally, the introduction of non-utility supply sources (as a result of PURPA) has established a more competitive generation market, replacing the traditional utility monopoly structure.

Mandating greater utilization of renewable energy has been an integral part of state utility regulatory reform. This has been achieved directly through modifying utility resource plans, providing incentives for non-utility development of renewables such differential treatment relative to fossil fuel cogeneration projects, and increased research and development allowances for certain technologies. Indirect support for renewable energy has come from regulatory restrictions on construction of conventional, central-station power supply.

For more traditional forms of renewable energy, rising costs and increased risks associated with conventional central-station powerplants have made these systems more competitive. At the same time, newer renewable energy technologies have enjoyed economic and regulatory incentives and have made initial entrees into the electric power market almost exclusively through third-party, independent power production. Renewable energy systems have achieved a level of acceptance that should ensure their inclusion in future utility resource plans. The level of penetration is being determined by technological improvements, but even more significantly, by state regulatory decisions.

This study has identified and described key factors that have influenced changes in the power generation market from the perspective of utility regulation at the state level. It has also characterized aspects of the interaction of regulators, utilities and independent energy producers in this environment. The intent is to illuminate the impact that state utility regulation has had on development of renewable energy technologies and to identify trends now underway that will have an impact on their development in the future.

In this complex regulatory environment we have identified several trends that should have a significant effect on renewable energy. These include: 1) encouragement of independent power production as a supplement or alternative to utility-generated electricity; 2) diversification of resources as a means of securing a reliable power generation mix; 3) selection of alternative energy paths as a means for reducing risks to utility ratepayers associated with utility and non-utility investments; 4) increasing competition among supply sources to encourage innovation and reduce costs; and 5) the introduction of least-cost planning as a way of prioritizing future resource options. These trends are not mutually exclusive, nor need they even be sequential. In fact, the current regulatory framework in many states includes action in several of these directions at once—all with the objective of securing low-cost, safe and reliable sources of electricity service in the near-and long-term.

PURPA has had a profound effect on market development paths for a number of the renewable energy technologies. For example, while the U.S. Department of Energy and the Electric Power Research Institute were seeking to develop a utility-scale, multi-megawatt wind turbine, independent power producers began introducing more technologically-ready small machines in clusters (windfarms) under PURPA. Similarly, federal rules limiting use of fossil fuels to 25

percent of annual energy input of qualifying renewable energy small power facilities have limited the development of hybrid renewable-fossil fuel systems. Finally, exemption limits regarding the Federal Power Act have established project capacity limits that could well interfere with the design of more optimally-sized systems for independent energy projects: i.e., solar thermal power plants could be more efficient at scales above 30 MW, but regulatory considerations have more or less arbitrarily established that size system as the project scale for developers.

The implementation of PURPA has also had an effect on research and development funding. In some cases, utility research and development efforts are being scaled back in favor of non-utility, PURPA-inspired development of the same technology. In other cases, where buy-back rates for independent power production have proven insufficient to encourage development of renewable technologies, state regulators have mandated increased utility research.

These and other implications of PURPA have induced some state utility regulators to adjust their emphasis upon protection of public welfare in the near-term to include greater consideration of general energy policy as dictated by the federal and their own state governments. However, forces still exist which prevent more attention to longer-term issues. One set involves the fact that the end of a strict monopoly structure in the power generation market has brought more parties into regulatory proceedings. This has made it more difficult for state commissioners to balance all of the represented interests. In many cases, consideration of a narrower set of petitioner interests has made it difficult to take a broad view of benefits and costs, so that decisions come to benefit one or more represented parties at the expense of longer range interests of consumers.

The relative successes and failures of PURPA have been identified. Many states have instituted their own PURPA-type regulations. Even more states have incorporated alternative energy and independent power generation into more traditional utility regulation. While the trends are clear, uniformity in state utility regulation has not been achieved.

The issues identified in this report are likely to receive greater attention as the overall energy situation changes and the role of alternative energy in the utility sector is further defined. Debate on issues such as cost recovery and diversification for utilities, and interconnection requirements and performance liability for independent power producers, should become clearer as we develop more experience with new technologies. With regard to changing energy needs, these issues may become more explosive because state regulators will appear to be retreating from support of alternative or renewable energy. In either case, once regulators become more familiar with renewable energy systems and the addition of independent power producers to traditional utility supply sources, more accurate assessments of the potential contribution of renewable energy will be available; this in turn will allow policies to be revised or modified more confidently. In the meantime, it appears that states will continue to experiment with many different and innovative approaches to satisfy their specific energy needs.

On the basis of the findings contained in this report, one can conclude that future prospects for market penetration of renewable energy in the utility sector will be determined largely by state regulation. This is due mainly to the reluctance of utilities to buy these systems directly, or their choice to enter the market through non-regulated subsidiaries that develop their own "independent" energy projects. In short, for renewable energy technologies to meet public policy objectives (e.g., greater market penetration as part of a diversified resource mix) and achieve technical and economic goals set for them (e.g., part of a least-cost resource plan), the regulatory community and the research and development community—both government and private—must be aware of each others activities .

Renewable energy appears to be riding a wave of regulatory reform. To the extent that this transformation results in realistic expectations for system cost and performance improvements, and then calls for greater utilization of renewable energy, the prospects appear promising. To date, and in the current environment, definition of the preferred applications and developers (both utility and non-utility) of these systems presents a real danger because many regulators are not adequately informed about current technology capabilities. On the other hand, well informed state regulators and policy makers can be powerful allies who will ensure that renewable energy technologies are included in future supply mixes. Consequently, as renewable energy technologies suitable for electricity production continue to mature, developers must closely monitor their state utility regulatory environment and changes in it.

STATE UTILITY REGULATORY PROFILES

To elaborate on the changing regulatory environment at the state level, REI has compiled profiles of nine states considered "innovators" in this area. The profiles describe each state's approach to the issues discussed in sections II and III of the report. Collectively, the profiles will serve as a guide to the many approaches used in regulating utilities and implementing the Public Utility Regulatory Policies Act (PURPA) of 1978.

Each state profile is organized into four sections. The first is a general overview of each state's electricity supply picture, with data on current and projected supply sources. If the state has recently implemented new policies or is considering changing current practices, they are mentioned in this section.

The second section covers the jurisdiction of agencies that regulate utilities and/or oversee the implementation of PURPA. Should more than one agency share authority for utility oversight and PURPA implementation, those agencies and their responsibilities are summarized.

The third section examines state utility regulation and how renewables may or may not be affected. Here, state utility resource planning, utility research and development, certificate of need regulations, cost recovery plans, and state attitudes towards utility diversification into non-regulated businesses are analyzed.

How each state profiled has implemented PURPA is the subject of the final section. Several concepts central to PURPA are discussed, including: how states define a QF; whether utilities are allowed to establish QF subsidiaries; how buy-back rates are determined: whether standard contracts are available; how interconnection requirements and back-up rates and services are established; whether wheeling of QF power to utilities and/or end-users is allowed; whether QF non-performance clauses and/or regulations exist; and what determines the availability of transmission capacity and who pays for any needed improvements or expansion.

In this review of state regulatory approaches REI has sought to ensure wide geographical representation: California and Nevada from the west, Wisconsin from the midwest, Florida and Texas from the south, and Maine, Massachusetts, New Jersey, and New York from the east. The nine states chosen, interestingly enough, are currently capacity-rich with the exception of some parts of Nevada. Several states around the country, when faced with this situation, have set low avoided cost rates. The states profiled here, however, have generally resisted this trend. Instead, they have attempted to balance policies designed to ensure low-cost and reliable electricity with policies to encourage new and emerging technologies. Some conclusions drawn from these reviews include:

- California, alarmed by its heavy dependence on fossil fuels for electricity generation, used several regulatory approaches to encourage QF development, including promulgation of four different standard contracts and avoided cost rates based on the most expensive energy source (oil). Following the decline in oil prices and an unexpected abundance of QF development, California has begun implementing a more market-oriented strategy, with bidding among QFs for available utility capacity as a major new initiative.

STATE UTILITY REGULATORY PROFILES

- Florida has aggressively promoted statewide wheeling and avoided capacity credits to avoid the construction of new, fossil-fueled facilities. In addition, the state is a national leader in the numbers of and energy generated by residential solar installations, biomass-fired cogeneration, and municipal solid waste facilities.

- Maine was the first state to adopt bidding among QFs as a means of allocating available utility generating capacity. The state is now carefully re-evaluating its regulations governing QFs and is expected to issue new regulations on wheeling and standard contracts.

- Massachusetts has instituted a bidding system, with extensive regulations requiring utility consideration of other parameters in a QF's bid besides the cost of capacity or power.

- Nevada was the first state to implement a least-cost planning program. The state also discourages the export of state electricity-generating resources through utility recapture provisions.

- The New Jersey Board of Public Utilities is aggressively implementing standard contract and wheeling provisions to create a new market for small power producers, especially cogenerators.

- After several court challenges, New York's as-available, minimum buy-back rate for QFs was upheld by the U.S. Supreme Court. Other initiatives include incentives for parties wishing to develop the state's hydro resources, and extensive requirements and regulations on interconnection of QFs.

- Among the states profiled, Texas relies most on a marketplace approach to implementing PURPA. Avoided cost rates are set as a "ceiling," never to be exceeded. Standard contracts are limited to QFs <100 kW, forcing most QFs to negotiate directly with utilities. Texas tries to encourage emerging technologies by requiring utilities to give preference to renewable and municipal solid waste projects when capacity needs permit. Texas has become a leader in mandatory wheeling as a result of policy designed to redistribute gas-fired cogeneration from the Gulf Coast.

- Wisconsin, which has recently approved least cost planning, is not only integrating the key elements of demand and supply-side planning but is also accounting for health, environmental and socio-economic impacts when evaluating resource options. Moreover, Wisconsin is a national leader in renewable energy research and development efforts. Since 1984, the state has required utilities to collect wind resource data and to test wind machines. The state is now actively promoting other renewable technologies through data collection and other research and demonstration projects.

Each profile is intended to be a guide—not a comprehensive survey of utility regulatory environment in these and other states. For that reason, we have listed at the top of each profile the address, phone number, and contact person for each state utility regulatory body, and urge individuals with more precise information needs to contact the state directly.

CALIFORNIA

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I. BACKGROUND

Because of its heavy dependence on oil and gas for electricity, California has made energy diversification a top priority. In the process, the state became an international leader in renewable energy development. Over 4,000 MW of QF capacity are on-line presently, with another 13,000 MW under contract (California Energy Commission. *Affordable Electricity in an Uncertain World: The 1985 California Electricity Report*, P106-85-001, May 1985, p. 67). Hydropower alone contributed 25% of California's electricity in 1985, while other renewables supplied 7% (U.S. Energy Information Administration, *Electric Power Annual*, July 1986).

As a result, California's dependence on oil for electricity has declined from almost 60% in the 1970s (California Energy Commission, The 1985 California Energy Plan, p. 6) to 2% in 1985. California utilities still rely heavily on natural gas, however, generating 50% of its electricity from this fuel in 1985 (U.S. Energy Information Administration, op. cit.). California received the balance of its electricity from nuclear in 1985, which constituted 15%. By 1996 the state's utilities project that only 25% of electricity generated in California will be from oil or gas (California Energy Commission. *Affordable Electricity*, op. cit., p. 67).

California now finds itself in a baseload electrical "energy glut," due to an oversupply of proposed capacity additions. The CEC has estimated the state will need new capacity additions totaling 21,383 MW through 1996. The CEC has identified 15,076 MW of capacity, leaving a shortfall of 6,349 MW. However, if the state goal of limiting oil- and gas-fired generation is factored in, there could be a net energy deficit of 22,854 GWh. The CEC has high hopes for geothermal and cogeneration projects, conservation and load management programs, municipal solid waste facilities, and renewable resources to make up the shortfall. Out of state power purchasing options also appear to have high potential for meeting future energy needs. Potentially, California could receive over 40,000 GWh from the Pacific Northwest (Ibid., p.5), and the Southwest could supply 27,000 GWh (Testimony of Commissioner Donald Vial, President, California Public Utilities Commission, before the Senate Committee on Energy and Natural Resources, July 23, 1985, p. 432).

California has experienced rapidly increasing electricity rates which have more than doubled in the last 10 years. The industrial sector has been especially hard hit, with electricity costs now 147% of the national average. Ten years ago, California industrial electricity costs were below the national average. These high costs have been cited as reasons for companies leaving or refusing to locate in the state. High fuel costs, accounting for 37% of overall electricity costs, are considered the major reason for skyrocketing electricity costs. The high fuel costs are due to guaran-

teed supply long-term, take-or-pay contracts utilities signed during the energy crises at high costs (California Energy Commission, *Affordable Electricity...*, op. cit., p. 6).

II. STATE UTILITY REGULATORY AUTHORITY

The California Energy Commission (CEC) estimates future demand, fuel prices, and energy supplies, as well as certifying sites for thermal power plants over 50 MW. The California Public Utilities Commission (CPUC) is responsible for implementing PURPA, and sets rates and the "reasonable" capital and operating costs of regulated utilities (California Public Utilities Commission Decision 86-07-004, July 2, 1986, p. 3).

III. REGULATION ON UTILITY ACTIVITIES

Resource Planning

Utilities must use the long-term electricity demand and supply forecasts by the CEC as the basis for resource plans they file biennially with the CPUC. If a utility disagrees with the CEC's assumptions or predictions, then the utility may submit an alternative forecast.

Cost Recovery

Utility generation projects and conservation programs are related to payments to QFs when the CPUC reviews utility proposal additions to the rate base. Based on its reviews of avoided costs, the CPUC may decide to not certify the project or impose "caps" on the amount of money a utility can recover from its ratepayers (Testimony of Donald Vial, op. cit., p. 416).

Research and Development Expenditures

California utilities have conducted extensive research and development on electric generating technologies, including renewables, annual spending has equalled $100 million. Utilities are now shifting more attention to end-user programs and conservation. California utilities have funded analysis of building energy use and pursued end-use technologies such as "smart meters" and "time-of-use" meters.

Recovery of EPRI dues are usually allowed through the rate base by the CPUC (Personal Communication, Julian Ajello, California Public Utilities Commission, November 10, 1986).

Utility Diversification into Non-Regulated Businesses

The CPUC approved a San Diego Gas and Electric (SDG&E) application to set up a holding company, but with conditions that has made SDG&E decide a holding company would not be attractive. Southern California Electric has established a separate corporate entity involved in independent energy project development.

IV. IMPLEMENTATION OF PURPA

Qualifying Facility Definition

California does not differ from FERC regulations in defining a qualifying facility (QF). (Personal Communication, Julian Ajello, California Public Utilities Commission, November 10, 1986).

Utility Ownership of QFs

The CPUC allows utilities to set up QF subsidiaries, as long as separate books are maintained. Two utilities formed QF subsidiaries: SDG&E eventually sold theirs, but Southern California Edison (SCE) still has one in operation (Personal Communication, Julian Ajello, California Public Utilities Commission, November 5, 1986).

Standard Contracts and Buy-Back Rates

Four types of standard offer contracts emerged in various forms. Standard offer contracts 1, 2, and 3 (referred to as SO1, SO2, and SO3) are predetermined contracts that require only signature of the developing entity to be effective. The QF remains free, however, to negotiate other provisions with a utility.

SO1 is for QFs that supply power on an as-available basis. For capacity payments, a combustion turbine is used as the proxy. Energy payments equal the price of the utility boiler fuel multiplied by an incremental energy rate (IER). The IER, in BTU/kWh, is the weighted average of utility marginal energy costs. Capacity payments and the IER are adjusted in general utility rate cases every 3 years, while energy payments are revised quarterly ("California Standard Offer 2 is Suspended," *PURPA Lines*, Vol. 2, No. 7, April 7, 1986, pp. 2-3). Capacity payments are divided into peak and mid-peak periods, with 80% of the capacity payments reserved for QFs producing during on-peak periods. Energy payments are divided into peak, mid-peak, and off-peak (Personal Communication, Julian Ajello, California Public Utilities Commission, November 10, 1986).

For QFs that can achieve capacity factors of at least 80%, a SO2 was available. Like the SO1, capacity payments were based on a combustion turbine, with the payments estimated, fixed, and levelized for the life of the contract to protect the QF from decreasing capacity values from any new system additions. QFs were eligible for bonus payments if their capacity exceeds 80%. Energy payment provisions were the same as SO1 (J.E. Ajello and D.I. Fellman, "The Development of Alternative Generation Resources in California," PG&E Energy Expo, April 1986, p. 2). SO2 was suspended, however, on March 19th, 1986, due to concerns that capacity payments were overpriced ("California Standard Offer 2 is Suspended," *PURPA Lines*, op. cit.). It is expected to be re-issued in early 1987, with a lower capacity price adjustment mechanism (Personal Communication, Julian Ajello, November 10, 1986).

The SO3 is for QFs <100 kW in capacity and is essentially a simplified version of SO1. The capacity payment is cut in half if the QF does not use time-of-day metering.

The SO4, a long-term standard project, is currently undergoing major revision, (CPUC D.86-07-004, July 2, 1986). The first SO4 (temporarily suspended in early 1985 and permanently suspended in July 1985) had three options available to QFs:

- The first featured pre-set escalating energy payments for the first 10 years of the contract, then payment to short-run avoided payments of the contract. To protect

oil- and gas-fired cogenerators from rising fuel costs under fixed electricity payments, those QFs would only receive 20% of their energy payments.

- The second option offered levelized energy payments that stayed constant throughout the length of the contract. To protect utilities from QFs that defaulted or abandoned tcontracts, QFs must post a security deposit. This option was not available to oil- and gas-fired cogenerators.

- The third option was aimed at oil- and gas-fired cogenerators. Energy payments were calculated by forecasting the Incremental Energy Rate (heat rate) for 10 years and the current price of the utilities' marginal fuel (usually gas). No fixed ¢/kWh prices were available under this option.

(J.E. Ajello and D.I. Fellman, "The Development of Alternative Generation Resources in California," op. cit., pp. 2-3).

The new SO4 requires each utility to submit biennial resource plans projecting electricity supply and demand for the next 12 years, as well as outlining their proposed resource additions and their costs for the first 8 years of the plan ("California PUC Issues Final Long-Run Standard Offer," *PURPA Lines*, Vol. 2, No. 14, July 14, 1986, p. 1). Each resource addition must pass a test of cost-effectiveness which compares the short-run marginal costs with and without the proposed resource addition. If the utility's short-run marginal costs are cheaper with the resource than without it, then the resource is considered cost-effective and is added to the utility's resource plan.

All cost-effective, proposed resource additions are potentially avoidable by QFs, unless a utility can successfully prove to the CPUC that a specific project should not be avoided due to beneficial impacts on the utility system (CPUC D.86-07-004, July 2, 1986, p. 40). The utility must prove cost-effectiveness; provide evidence that the system characteristics support a "finding of non-deferrability" supply data on the economic and operational benefits of the project, and assess the impact if QFs supplied the capacity and generation rather than the project (Ibid., pp. 83-84). If no additional capacity or generation is needed, then the avoided cost will be based on short-run marginal utility costs (J.E. Ajello and D.I. Fellman, "The Development of Alternative Generation Resources in California," op. cit., p. 6). Should a utility need capacity or generation, it must make public its estimates of the fixed and variable costs of the proposed resource additions. QFs then have 3 months to file a bid to "avoid" the the addition. In their filing, QFs must choose the resource it will avoid, submit QF capacity, and state the lowest percentage of fixed costs the QF will accept as payment. If the capacity of the QF applications does not surpass the avoided resource unit's capacity, then all QFs are offered standard contracts at the fixed (avoided) cost for the utility proposed new capacity. If the capacity is exceeded, then all winning bidders will receive contracts at the price of the lowest *losing* bid ("California PUC Issues Final Long-Run Standard Offer," op. cit., p. 2). Contracts are not to extend beyond 15 years from the QF on-line date (CPUC D.86-07-004, July 2, 1986, p. 98). Levelized or front-loaded pricing is no longer available (Ibid., p. 78), and a 4th pay period--minimum load or deep off-peak--has been added to the SO4 contract (Ibid., p. 31).

Avoided cost payments will differ depending on whether the QF avoided a generating resource or meets near-term demand. If the former, the payments are based on the capital and operational costs of the avoided resource. ("California PUC Issues Final Long-Run Standard Offer," op. cit., p. 2). For the latter, the QF receives utility marginal cost payments. During the period after the contract is signed but before the QF comes on-line, payments to QFs will be based on the utility's short-run marginal operating costs, with IER adjusted quarterly (CPUC, D.86-07-004, July 2, 1986, pp. 77-78).

A QF is not required to simulate the avoided resource addition to qualify for a S04 (Ibid., p. 73). The CPUC has encouraged the use of QF pooling if it would make their bid more attractive and better meet utility load requirements (Ibid., p. 96).

QFs are also eligible for performance payments, or "adders", should they be asked to supply additional features beyond contract requirement, e.g., more curtailment hours, voltage control, dispatchibility. Currently, the state's utilities are preparing reports on the feasibility of adders at the direction of CPUC. Their report should address issues such as provisions QFs must meet to become eligible (technical specifications, geographic limitations, minimum and/or maximum QF capacity requirements, and utility/QF coordination in implementing the adder). The price of the adder will be set on the cost the utility would pay to supply the feature itself, and the adders will be for a length of 10 years, after which they can be extended for 5 years at a revised price (Ibid., pp. 74-75).

Interconnection Requirements

To be connected to the utility grid, each QF must agree to install, at its expense, connection, transformation, switching, metering, communication, control, protective, and safety equipment, plus any additional or reinforcing equipment the utility may deem necessary (California Public Utilities Commission Rule No. 21, July 7, 1982, p. 1). In operating its facility, the QF must be in parallel with the utility's system at all times, determined by the utility's system dispatcher. Normally, the system dispatcher will cede this authority to a designated switching center. The QF must also maintain a log, keeping track of the system's unit availability, maintenance outages, circuit breaker activation requiring manual reset, or "unusual events." The utility may examine the log at its request (Ibid.,p. 3).

In general, QFs pay utilities in full for any costs required for interconnection, unless the QF negotiates a payment plan with the utility (Personal Communication, Julian Ajello, California Public Utilities Commission, November 5, 1986).

Back-Up Rates and Service

QFs pay back-up and/or stand-by rates in accordance with their customer classification, which in turn is set by the QFs power demand. In addition, QFs pay a monthly $/kW fee, which applies whether the QFs does or does not purchase back-up or stand-by power (Personal Communication, Julian Ajello, California Public Utilities Commission, November 10, 1986).

Wheeling QF Power

In general, wheeling rates must be negotiated between the utility and the QF (NARUC Response). Under a new state law, cogenerators are allowed to sell power to two other customers on adjacent property without being considered a utility (Personal Communication, Jan Hamrin, Independent Energy Producers, November 18, 1986).

Transmission Availability and System Upgrades

New or upgraded transmission facilities are generally assumed to have system-wide benefits and therefore costs are recoverable through the rate base. If, however, a utility can prove that QFs

will be the sole beneficiaries, QFs must pay the costs of the new or upgraded transmission facilities (CPUC Decision No. 85-09-058, p. 4).

California has experienced severe transmission shortfalls in some parts of the state, the most serious of which occurred in the northern part of the state. An interim solution devised by the utility, QFs, and the CPUC staff (D.84-08-037) required PG&E to submit a list of transmission improvements needed over a five year period. These improvements allowed 1,150 MW of QFs to be interconnected, and required PG&E to add them to the system upon application even if the transmission improvements were not made and PG&E had to down some of its own power to accommodate the new QF capacity.

The additional capacity the agreement provided for was exhausted within six weeks, creating a "commodities market" in transmission capacity and giving rise to concerns on when or if the applying QFs would come on-line. In response, a "QF Milestone Procedure" was instituted (D.85-01-038), again through QF, utility, and CPUC staff negotiations. QFs must meet certain criteria under a specific timetable, such as providing a project description, showing proof of site control, paying a $5/kW project fee into a escrow account as earnest money, filing a critical path permit, and meeting other deadlines specified in the project development schedule. The utility's obligation to buy power from the QF is dropped if the QF misses a milestone or abandons the project. Previously, QFs had 5 years to come on-line after an agreement was signed (Ibid., p. 5). The CPUC is considering additional changes in the QF Milestone Program (CPUC D.86-07-004, July 2, 1986, pp. 88-89).

Performance Requirements and Security Payments

The $5/kW fee QFs pay under the QF Milestone Procedure is equivalent to a security deposit. If the QF does not come on-line, than the QF forfeits the fee.

QFs receiving front-loaded energy payments must post a security deposit. QFs considered firm capacity must meet or exceed a 80% capacity factor during summer, on-peak periods. If this requirement is not met, the QF will receive a reduced capacity payment, or not receive the payment at all (Personal Communication, Julian Ajello, California Public Utilities Commission, November 10, 1986).

Finally, utilities are advised in all the standard contract offers that the contract "does not constitute the sole remedy" (Personal Communication, Jan Hamrin, Independent Energy Producers, November 18, 1986). In other words, if the QF does not come on-line as contractually obligated, and the utility must purchase energy or capacity to replace the projected QF production, then the utility may sue the QF for damages (Personal Communication, Julian Ajello, California Public Utilities Commission, November 10, 1986).

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I. BACKGROUND

In 1984 coal supplanted oil as the primary fuel used in Florida for electricity generation, supplying 31% of Florida's electricity as opposed to oil's 17%. This represents a significant change from 1974, when over 50% of the state's electricity generation was due to petroleum and supplied just 18% came from coal. Nuclear power experienced the largest increase during that period, up to 22.9% from 10.8%. Natural gas contributed 15.4% (Governor's Energy Office. *Florida Energy: Data 1970-1984*, December 1985, p. 53).

Florida, is a national leader in renewable energy development. Renewable energy sources accounted for 6.1% and 1.7% of total state energy and electricity supplies, respectively, in 1984 (Ibid., p. 72 and 53). The growth in renewable energy consumption in Florida has been explosive, increasing 91.6% since 1974. Wood is the largest contributor, supplying 117 trillion BTUs or 75% of the total energy supplied by renewables in 1984. Florida is also a national leader in energy generated from municipal solid waste (MSW) facilities, with five plants generating 17.6 trillion BTUs of energy. The burning of crop residues, mostly bagasse from the sugar cane industry, generated 13.1 trillion BTUs or 8.4% of Florida's renewable energy supplies in 1984. In the residential sector, approximately 106,000 solar heating and cooling systems produced 2.3 trillion BTUs of energy in 1984. Hydropower, photovoltaics, and wind contributed the rest of Florida's renewable energy (Ibid., pp. 72-73).

The development of reliable renewable electric supplies is particularly important to Florida, since it imports the majority of the fossil fuels used for electricity generation (Ibid., p. 72). In addition, interstate electricity purchases are increasing dramatically. Imported power accounted for 11.5% of the state's electricity consumption in 1984, 3.5 times their 1981 level (Ibid., p. 53).

II. STATE UTILITY REGULATORY AUTHORITY

The Florida Public Service Commission (FPSC) has jurisdiction over setting utility retail rates, prescribing and enforcing safety standards for electricity transmission and distribution, and the planning, development, and maintenance of the state electric power grid (Florida State Statutes 366.04, pp. 354-355).

III. REGULATION OF UTILITY ACTIVITIES

Resource Planning

The FPSC holds annual hearings to review utility resource plans and to approve strategies for meeting demand for generation and transmission (Governor's Energy Office. *Energy: 1985 Annual Report to the Legislature,* January 1986, p. 34). At these hearings, each utility files its next planned, avoidable generating unit, supplying an analysis of the proposed plant's size, development schedule, operating characteristics, and cost. The FPSC will determine the type and proposed in-service date of the statewide avoided unit for setting energy and capacity rates (FPSC Rule 25-17.083, p. 17-48).

Florida State Law (Chapter 23.0191, Florida Statutes) also requires electric utilities to file 10-year plans outlining projected electricity and capacity demand, and the location of possible powerplant sites to the Florida Department of Community Affairs (FDCA). The FDCA reviews these plans and the FPSC's own projections of electricity and capacity demand (Governor's Energy Office. *Energy: 1985 Annual Report to the Legislature,* op. cit. p. 39).

The FPSC has publicly supported the development of small power producers to displace fossil fuels as electricity generators, to avoid the need for other generation facilities, and to increase the reliability and integrity of the electrical system (Ibid., p. 36). Since 1980, the FPSC has approved 9 new generating facilities, 4 of them fired by solid waste. Those 4 plants have a total initial capacity of 186.5 MW, with a final capacity of 239.1 MW when all the plants are in-service (Ibid., p. 35). In 1984, new legislation was approved, at the request of the FPSC, to provide incentives for the development and construction of energy-generating resource recovery facilities. The act requires electric utilities to provide capital for government-owned resource recovery facilities prior to construction, considering the funds early payments for capacity to be delivered to the utility once the facility is placed in-service. The maximum level of funding allowed is the same as the cost of the electric generation and transmission equipment associated with the facility. The facility must be considered cost-effective to the utility's ratepayers before it can receive utility capacity payments (Ibid., p. 41).

Power Plant Certification

The Florida Department of Environmental Regulation issues the certificates approving the construction of any new central station facility over 50 MW. However, several state agencies must submit reports on the proposed facility before the certificate can be issued (Florida State Statute 403.504, pp. 893-894). The FPSC, for example, must determine the need for a new power facility, deciding whether the proposed plant is the most cost-effective, if there is need for capacity, how the proposed facility affects on system reliability and integrity, and whether adequate consideration has been given to conservation (Florida Statute 403.519, p. 898). The Florida Department of Community Affairs must file a report on how the proposed power production facility coincides with the state comprehensive plan. A report must also be filed by the water management district as to where the proposed facility is to be located and how the facility will impact the area. In addition, The Department of Environmental Regulation must conduct studies on the plant's cooling requirements, construction and operational safeguards, accessibility to transportation systems, soil and foundation conditions, effects on present and projected water supplies, impacts on surrounding land uses, proximity to transmission corridors, and overall environmental impacts (Florida State Statute 403.507, p. 895).

Cost Recovery

If a utility negotiates a separate contract with a QF for firm capacity and energy, utility payments to QFs are eligible for cost recovery if they meet the following provisions:

- Firm energy and capacity purchases can be expected to defer or avoid new capacity.
- The cumulative present worth of firm energy and capacity payments does exceed the cumulative present worth of the value of a year-by-year deferral of the statewide avoided unit over the terms of the contract.
- If the total present worth (levelized cost) of firm energy and capacity payments does exceed the present worth of deferring a statewide avoided unit, the QF must provide security in the form of a surety bond, an agreement to receive smaller avoided cost payments or a contract to reimburse the utility.

(FPSC Rule 25-17.083, p. 17-48)

Utility payments to as-available or firm QFs under standard contracts are recoverable through the Fuel and Purchased Power Cost Recovery Clause, if the FPSC is convinced such payments are in the ratepayers' best interests (Ibid., pp. 17-48 and 17-53).

Research and Development Expenditures

The Florida State Legislature and the FPSC have openly encouraged research and development programs, with the Legislature encouraging "experimental rates, rate structures, or programs" if needed to assure "efficient and cost effective energy" (Florida State Statute 366.81, p. 360). To further this goal, the Florida Energy Trust Fund was created. It mandates that the FPSC develop test programs to be conducted in the service areas of one or more utilities for energy conservation measures. The FPSC is also allowed to allocate money from the fund to support educational projects to "develop and demonstrate appropriate technology...for efficient utilization of electricity and natural gas" (Florida State Statute 366.84, p. 361).

The FPSC usually allows utilities to recover all EPRI dues (Personal Communication, Jack McLean, Florida Public Service Commission, November 10, 1986).

Utility Diversification into Non-Regulated Businesses

The FPSC has not issued any wide-ranging orders in this area, preferring to examine each utility proposal on a case-by-case basis. The FPSC has indicated its intent to follow the issue closely and to disallow costs for inclusion in the rate base it considers "unreasonable and imprudent" (FPSC Order No. 15885, March 24, 1986).

IV. IMPLEMENTATION OF PURPA AND RELATED ISSUES

Qualfiying Facility Definition

The FPSC does not depart from the FERC definition and criteria that a small power producer or cogenerator must meet to achieve the status of a QF (FPSC Rule 25-17.080, pp. 17-44 to 17-45).

Utility Ownership of QFs

The FPSC follows FERC regulations that do not allow QFs to be 50% or more owned by a regulated utility (Personal Communication, Mike Twomey, Florida Public Service Commission, November 20, 1986).

Avoided Cost and Buy-Back Rates

QFs can sell power and capacity on an as-available basis or through net sales to the utility. If a QF wishes to change its billing arrangements, it must not do so more than once a year, must give 30 days written notice, coincide the change with the next Fuel and Purchased Power Cost Recovery Factor billing period, and reimburse the utility for any additional metering or other equipment required to implement the change. Short-run, "as available" rates based on the utility's marginal fuel costs can be obtained by QFs (NARUC Response). QFs below 100 kW in capacity can use hourly recording meters, dual kilowatt-hour register time-of-day meters, or standard kilowatt-hour meters and operate under a net billing arrangement (FPSC Rule 25-17.082, p. 17-45).

Long-run rates encompass both the energy and capacity payments (NARUC Response), using the avoided cost of a baseload coal-fired plant consisting of two 700 MW units. The estimated capital cost, using a April 1992 in-service date, is $2044/kW ($1983). QFs can receive partially levelized, "early capacity payments" up to 7 years before the proposed in-service data of the avoided plant (FPSC Docket No. 830377-EU, Order No. 13247, May 1, 1984, pp. 4-9). Capacity payments are available only to QFs with long-term contracts, with projects on-line by the in-service date of the avoided unit, and with capacity factors of 70% or more (NARUC Response). The QF can choose fixed or annually revised capacity payments but cannot change the rate or schedule of the payments once the QF agrees to a payment schedule (FPSC Rule 25-17.083, p. 17-48). Long-run energy payments are based on the cost of fuel, in ¢kWh, that would have been burned at the statewide avoided unit (Ibid., p. 17-51).

Standard Contracts

A utility and a QF may negotiate a contract apart from available standard contracts. All such contracts must be filed with the FPSC. Any disputes arising from contract negotiations may be brought to the FPSC for settlement (FPSC Rule 25-17.0831, p. 17-53).

Interconnection Requirements

A utility must interconnect with a QF in the utility's service area that agrees to reimburse the utility for interconnection costs and abides by state interconnection requirements. The utility has the right to examine each interconnection request on its own merits. Should the QF feel it has been unduely rejected, it can appeal to the FPSC, with the burden of proof on the utility to show why its interconnection standards are reasonable and why the interconnection should not be allowed.

The process begins with the QF filing an application for interconnection with a utility. The application must include layout drawings, all associated equipment specifications and characteristics, system data and diagrams, power requirements in watts and vars, expected radio-noise, harmonic generation, telephone interference factor, synchronizing methods, and operation and instruction manuals (FPSC Rule 25-17.087, pp. 17-53 to 17-54). At least 15 days

before the start of any interconnection work, the QF will provide the utility with proof of a liability insurance policy for not less than $300,000. The insurance company will notify the utility if the policy is changed or canceled, giving at least 30 days written notice (Ibid., p. 17-55 to 17-56).

The QF must pay all costs from the addition or upgrading of protective devices, transformers, lines, services, meters, switches, and other equipment and devices that would be required to provide normal utility service to the QF. The utility must give a written cost estimate of the labor and equipment required, as well as a timetable and a feasibility report (Ibid., p. 17-58). The QF can pay the utility in full or reimburse the utility through monthly payments, paying interest at the 30 day commercial rate (Ibid., p. 17-54). The payback period must not exceed 3 years (FPSC Docket No. 830377-EU, Order No. 13247, May 1, 1984, p. 17). The QF must meet minimum guidelines concerning the quality of service it provides the utility, including frequency, voltage, harmonics, power factor (Ibid., p. 17-59), and DC generators. Metering equipment will be installed by the utility at its expense to measure capacity and energy deliveries to the QF. The utility will provide, at the QF's expense, necessary metering equipment designed to measure QF energy deliveries to the utility. In addition, the QF will ensure its project will operate safely by installing protection equipment and disconnection switches. The utility may disconnect the QF for system emergencies, scheduled system maintenance, existence of dangerous conditions on the QF's generating or protective equipment, negative impacts on utility service to its customers, and/or failure of the QF to maintain its insurance coverage or to follow local, state, and federal rules, regulations, orders, or decisions. The QF must allow utility employees to inspect and/or test the QF's equipment and facilities (Ibid., p. 17-55).

Back-Up Rates and Service

The utility shall provide supplemental or back-up power at the QF's request. The rates charged will be the retail prices assessed to retail customers in the QF's tariff classification (i.e., residential, industrial, etc.). The FPSC held three days of hearings on stand-by rates in August. The FPSC staff's basic position is that rates charged should recognize the diversity and coincidence characteristics of stand-by customer loads. The FPSC will vote on the issues on December 1, 1986.

Wheeling QF Power

To encourage the development of QFs and to avoid or defer the need for new generating units, the FPSC established a statewide, wholesale market for the sale of energy and capacity from QFs to utilities. At the QF's request, each utility must wheel as-available or firm QF energy and capacity to another utility (FPSC Rule 25-17.088, p. 17-58), unless the receiving utility's rates will be detrimentally affected ("States' Cogeneration Rate-Setting Under PURPA," Part 2, *Energy User News*, September 16, 1985). Interstate and intrastate wheeling are permitted (FPSC Order No. 15053, September 27, 1985, p. 10). QFs are responsible for all transmission service charges, line losses and any inadvertent energy flows due to the wheeling of QF energy and/or capacity. Wheeling rates, and the availability of transmission systems for wheeling, are filed by electric utilities with the FPSC (FPSC Rule 25-17.088, p. 17-58). QFs are generally not allowed to transmit power from one of their locations another unless it can be proven that such an action will not cause higher electricity costs to the utility's customers or affect the quality of utility service (FPSC Order No. 15053, September 27, 1985, p. 11).

Transmission Availability and System Upgrades

Presently, there is an adequate amount of transmission capacity in Florida (Personal Communication, Jack McLean, Florida Public Service Commission, November 10, 1986).

Performance Requirements and Security Payments

The following performance criteria applies only to QFs that supply firm energy and capacity, unless a contract specifically negotiated between the QF and the utility provides for other performance standards:

- The QF must provide monthly generation estimates each October 1st for the following year.
- The QF must update its annual generation schedule when any changes are deemed necessary.
- The QF must decrease its generation or take other appropriate action at the request of the utility for safety reasons or to preserve system integrity.
- The QF must coordinate scheduled outages with the purchasing utility
- The QF must comply with the purchasing utility's reasonable requests regarding daily or hourly communications

In addition, all QFs providing firm energy and capacity must meet a 70% capacity factor averaged over a year. In the QF's first year of operation, the average capacity factor will be determined by the total kilowatt hours of generation sold to the utility by the QF, then divided by the capacity of the QF and time elapsed since the QF's in-service date (FPSC Docket No. 830377-EU, Order No. 13247, May 1, 1984, p. 13).

The consequences of not meeting the performance criteria for QFs under a standard contract depends on what type of capacity payment option they choose. QFs wishing to receive "early" capacity payments before the avoided plant is scheduled to come on-line generally will receive greater punitive sanctions than QFs receiving "normal" capacity payments after the scheduled on-line date of the avoided plant. QFs receiving the early capacity payments that do not meet performance criteria *before* the scheduled on-line date of the avoided plant will not receive capacity payments until they comply with performance requirements. If QFs that are receiving early capacity payments do not meet performance requirements *after* the proposed in-service date of the avoided plant, they will not only be ineligible for capacity payments, but they also must pay the utility the difference of what the QF would have been paid had it selected "normal" capacity payments and what it would have received in "early" capacity payments had it met the performance criteria. QFs under the "normal" capacity payment schedule that do not meet the performance criteria will simply not receive capacity payments until they meet performance requirements, regardless of whether the scheduled avoided plant in-service date is in effect (Ibid., p. 14).

MAINE

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I. BACKGROUND

Maine currently relies on oil, utility-owned hydro, and nuclear power for its electricity generation, each providing about one third. In 1981, the Maine Public Utility Commission (MPUC) turned down an application for a combined cycle facility, choosing to emphasize Canadian Hydro purchases, small power production, cogeneration, and other utility power purchases for meeting future energy and capacity requirements. By the year 2000, the MPUC projects that 20-30% of the state's electricity will come from Canadian power purchases, 30% from QFs, and the remainder from hydro, fossil fuels, and nuclear (Personal Communication, Richard Darling, Maine Public Utility Commission, September 16, 1986).

In 1984, Maine adopted regulations requiring QFs larger than 1 MW to competitively bid to supply utilities with energy and capacity, making it the first state to adopt a QF bidding process ("State Summaries of Major Cogeneration Issues," Phipps Group, p. A-16). These regulations are being re-evaluated, and it is expected the MPUC would issue new regulations in late 1986 or in early 1987 ("Maine Drafts Chapter 36 Changes," *PURPA Lines*, Vol. 2, No. 19, September 29, 1986, p. 1).

II. STATE UTILITY REGULATORY AUTHORITY

The Maine PUC has exclusive authority over rate-setting, implementing PURPA and utility resource planning. Environmental standards are usually set by the state Department of Environmental Protection (Personal Communication, Richard Darling, op. cit.).

III. REGULATION OF UTILITY ACTIVITIES

Resource Planning

Maine utilities are required to file annual resource plans, of which blocks of capacity ("decrements") are earmarked for purchase from QFs. Decrements are utility specific, equal to 50 MW for utilities with demand of 500 MW or more, or 10% of peak demand for utilities with a smaller peak demands (MPUC Order No. 84-234, Chapter 36, May 30, 1985, p. 8). Central Maine Power is the only utility with a 50 MW decrement; Bangor Hydroelectric and Maine Public Service have decrements of 24 MW and 12 MW, respectively (Personal Communication, Richard Darling, op. cit.).

Power Plant Certification

A "certificate of convenience and public necessity" is required by the MPUC before a new power plant can be built. Some of the factors considered by the MPUC before such a certificate is issued include cost, amount of capacity required, and whether other alternatives (i.e., power purchases and/or small power production) should be used (Personal Communication, Richard Darling, op. cit.).

Cost Recovery

Other than utility-owned hydro facilities, there are no known cases of utilities recovering costs from a commercial or demonstration renewable electric facility. Payments to QF facilities are usually considered recoverable.

Research and Development Expenditures

Internal utility R&D funding is generally allowed in the rate base. As a rule, portions of engineering work for unconstructed or abandoned generation plants are not passed through the rate base.

EPRI dues are not allowed in the rate base (Personal Communication, Richard Darling, op. cit.).

Utility Diversification into Non-Regulated Businesses

A formal decision has never been issued by the MPUC; however, a utility request for a ruling was withdrawn after opposition was expressed by the Maine Commissioners (Personal Communication, Richard Darling, Maine Public Utilities Commission, October 29, 1986).

IV. IMPLEMENTATION OF PURPA

QF Definition

Maine does not depart from the FERC definition of "qualifying facility" (MPUC Docket No. 84-234, op. cit., pp. 5-7).

Utility Ownership of QFs

Utility-owned QF subsidiaries are allowed in Maine if separate books and accounting procedures are maintained. As with other QFs, a utility-owned QF subsidiary must follow all avoided cost and standard contract regulations (Personal Communication, Richard Darling, op. cit.).

Avoided Cost and Buy-Back Rates

All avoided cost rates are calculated using a revenue requirements model. Utility revenue requirements are calculated with and without QFs, with the difference then divided by the anticipated QF energy generation.

The energy component of avoided cost rates is based on utility production costs, as calculated with and without QFs on-line and divided by the expected energy generation of QFs. The capacity portion of avoided cost rates is determined by avoided utility capacity additions, as specified in each utility's resource plan for the next 15 years. Capacity payments are only available to QFs under a long-term contract (NARUC Response and MPUC Docket No. 84-234, op. cit., p. 8). QFs can supply power on an as-available or firm supply basis. If the latter, the QF can choose an avoided cost rate based at the time of delivery or when the contract is signed (MPUC Docket No. 84-234, op. cit., p. 17).

Avoided cost rates are updated annually and are available on a variable or fixed, levelized basis for long-term contract holders. Short-term contracts under one year in duration receive variable payments only. Full avoided cost is guaranteed to QFs under 1 MW under a standard contract, although these QFs may negotiate contracts with a utility. QFs over 1 MW must negotiate with the utility and may or may not receive full avoided cost. Levelized or front-loaded payments are allowed, but they must not exceed the total avoided cost amount as calculated over the length of the contract (NARUC Response).

Standard Contracts

Standard contracts of full avoided cost are available to QFs under 1 MW on a short-term basis or for 5, 10, and 15 years. QFs under 100 kW can operate on a net billing arrangement ("States' Cogeneration Rate-Setting Under PURPA," *Energy User News*, September 30, 1985, Part IV). QFs not falling in these categories must negotiate directly with a utility for a power purchase agreement (NARUC Response).

Interconnection Requirements

No utility can refuse to purchase energy or capacity from a QF or enter into a long-term contract with a QF unless the utility provides evidence that such purchases will result in negative avoided cost rates, or the QF fails to meet the following criteria:

- Right of ownership or interest in land or waters required for project development.
- In possession of necessary local, state, and federal permits, variances exemptions, and licenses. The QF may sign an agreement to meet this requirement by a specified time.
- Can provide evidence of adequate capital and/or financing to develop an build the proposed facility, e.g., a letter of commitment from a financial institution, internal financing, or the sale of stock/partnership shares.
- In receipt of executed contracts for any necessary fuels for energy generation, including supplemental or back-up requirements. Hydro facilities must provide hydrological data concerning water availability.
- For cogeneration facilities, a description on alternative uses of steam other than for power generation.
- A construction timetable and means and methods of building the facility.

- Signed contracts for the project's operation and maintenance, as well a maintenance schedule for the duration of a long-term contract.

(MPUC Docket No. 84-234, op. cit., pp. 12-13).

All interconnection costs are the responsibility of the QF. Several payment plans are available for QFs:

- Direct purchase or installation of interconnection equipment by the QF.
- Direct purchase and installation by the utility, with the QF leasing the equipment for the lesser of 24% of the installed cost, or the amount permitted by tariff.
- Direct purchase and installation by the utility, with the QF reimbursing utility over a period of 5 years or less.

In no case shall the utility have to buy or install equipment not in regular use for power generation facilities (MPUC Docket No. 84-234, op. cit., pp. 20-21).

Back-Up Rates and Service

A utility must provide back-up power, supplementary power, maintenance power, and interruptible power to QFs upon the QF's request. The utility can refuse if it can show that providing such power will affect its service to its customers and "place an undue burden on the electric utility" (MPUC Docket No. 84-234, op. cit., p. 20). In practice, only Central Maine Power, the state's largest utility, provides back-up power to QFs and only on an unguaranteed, as-available basis. Back-up rates are set by the MPUC and are the same as the short-term avoided cost rate, with a fuel cost adjustment (Personal Communication, Richard Darling, op. cit.).

Wheeling QF Power

Wheeling rates are not set by the MPUC at this time; however, utilities have agreed to wheel power from QFs at rates similar to what is charged to other utilities (NARUC response). The MPUC was in the midst of studying wheeling and planned to issue a report in late 1986. Among the issues to be explored are who should finance existing and new transmission lines, who decides on wheeling access and wheeling rates, the impacts of transmitting power between non-utility parties within the state, and the consequences of large customers going "off-grid" and generating their own power ("Maine Mulls Avoided Cost Rules," *PURPA Lines*, op. cit., p. 5).

Transmission Availability and System Upgrades

There has been some concern expressed over possible transmission capacity shortfalls. These concerns helped prompt the wheeling study (see above). In some cases where utilities have worked with QFs on siting, QFs have lessened rather than contributed to transmission demand because they were placed closer to rural, outlying areas, reducing the need for transmission lines (Personal Communication, Richard Darling, op. cit.).

Performance Requirements and Security Payments

A security deposit, in the form of a letter of credit or a bond, is usually required. In addition, the QF must reimburse the utility for lost energy and capacity if their project is abandoned once the project comes on-line (Personal Communication, Richard Darling, op. cit.).

MASSACHUSETTS

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I. BACKGROUND

In 1985 Oil and coal provided most of Massachusetts' electricity in 1985, 43% and 25%, respectively. Nuclear (18%), gas (13%), and hydro (1%) were also electricity suppliers. By 1990, hydro is expected to increase to 10%, due to purchases from Canadian hydro facilities, and oil is expected to fall to about 33% (*Electric Utility Industry in New England Statistical Bulletin 1985*, Electric Council of New England, pp. 4 and 13).

After a period of negative electricity demand, Massachusetts is experiencing an upswing in demand, estimated at 5% annually. Utilities are becoming interested in renewable QFs because of their modularity and the shift of financial responsibility from the utility to the QF developer.

II. STATE UTILITY REGULATORY AUTHORITY

The Massachusetts Department of Public Utilities (MDPU) is responsible for the regulation of the eight investor-owned electric utilities in the state. Licensing and siting new generating facilities and overseeing the development of utility resource plans are the responsibilities of the Massachusetts Energy Facilities Siting Council (MEFSC).

III. REGULATION OF UTILITY ACTIVITIES

Resource Planning

The MEFSC is responsible for reviewing the long-range supply and demand forecasts made by public and private electric and gas companies.

Power Plant Certification

An applicant for a power plant must receive two types of approval by the MEFSC. First, MEFSC approval must be sought for any facility 100 MW or over before constructing the plant. The applicant must answer why power from the facility is needed, the cost and environmental

impacts of the facility, and the other generation and non-generation alternatives considered in the assessment of need. To get MEFSC approval, the applicant must prove that a reasonable number of alternatives were evaluated and that the proposed facility meets the MESFC's mandate of supplying an adequate amount of energy at the least possible cost, with minimal impact on the environment.

Second, although not all power facilities need to acquire this permit, the applicant may have to acquire a "certificate of environmental impact and public need" (M.G.L., Ann. ch. 164, sec. 69k), A power facility developer may file an application for this permit when the proposed project cannot meet standards issued by another state or local agency with commercially available technology; when another state or local agency has unreasonably delayed the issuance of necessary approvals; if the developer feels there are inconsistencies among the resource use permits issued by different state and/or local agencies; or that the project cannot be built due to disapproval, conditions, or denials issued by other state and/or local agencies. For a certificate to be issued, the MEFSC must find that the proposed facility is needed, that there has been adequate consideration of environment, public health, and public safety issues, that the facility may not meet certain state and/or local laws but should be exempted from them because the facility provides an adequate supply of energy at minimal environmental impact and cost, and that the facility is in the public interest. If this certificate of issued, it will supersede all other state and/or local permits.

Cost Recovery

Utilities can recover QF payments through each company's quarterly adjusted fuel charge (MDPU Order 84-276-B, August 25, 1986, Regulations, p. 4).

Research and Development Expenditures

No specific guidelines exist for utility cost recovery of research, development, and demonstration expenditures. The MDPU evaluates utility expenditures in this area on a case-by-case basis.

Utility Diversification into Non-Regulated Businesses

No order has been issued specifically addressing this question, although one utility has petitioned to establish a subsidiary that would, among other things, develop QFs. The petition is currently under MDPU investigation (MDPU 86-66).

IV. IMPLEMENTATION OF PURPA

QF Definition

Massachusetts does not depart from the FERC definition of QF "qualifying facility."

Utility Ownership of QFs

See: "Utility Diversification into Non-Regulated Businesses."

MASSACHUSETTS

Avoided Cost and Buy-Back Rates

Short-run energy purchase rates are based on a quarterly projection of the utility's avoided fuel and variable O&M costs, as approved by the MDPU.

Short-run capacity payments are available if the utility is in need of capacity, or would be capacity short if it were not for the QF. Such payments are contingent on New England Power Pool (NEPOOL) recognition of the short-run capacity value of QFs. The rates are based on a capacity deficiency charge levied by NEPOOL when utilities fail to meet their NEPOOL determined capacity requirements. Long-run energy purchase rates are based on the utility's marginal fuel, O&M, and capitalized energy costs over a 20-year planning period. Capitalized energy costs are defined as the levelized real revenue requirements of the next avoidable utility capacity addition, minus the revenue requirements from the cost of a utility peaker, excluding fuel and variable O&M (Ibid., p. 17).

Long-term capacity payments are available if the utility plans to add capacity through new generating units, power purchases, or through conservation and load management within a 20 year planning period. Long-run capacity rates are based on the levelized real revenue requirements of a utility generating unit, excluding fuel and variable O&M costs (Ibid., p. 25).

Standard Contracts

Five methods exist for QFs to sell electricity to utilities:

- A QF can sell power to a utility without a contract at the as-available rate. QFs below 30 kW may operate under a net billing arrangement at a non-time differentiated rate, based on the utility's avoided energy costs in peak and off-peak periods. For QFs over 30 kW, energy will be metered and purchased at time-of-supply, with separate rates for peak and off-peak periods.

- QFs may sign a contract with a utility to sell power on an as-available, long-term basis at the short-run energy purchase rate.

- QFs may choose to negotiate terms and rates directly with the utility, subject to MDPU approval.

- QFs with capacity of 1 MW or less may sign a long-run standard contract (B) at a fixed long-run purchase price based on the weighted average of the bidding prices of QFs successfully competing in the bidding procedure.

- QFs may sign a long-run standard contract (A) with a fixed long-term price based on a utility's 20-year projection of avoided fuel, variable O&M and capacity costs. Such contracts are awarded annually through a competitive solicitation and *bidding* procedure that evaluates both price and non-price characteristics of a QF proposal (see below). Contracts are written at the price submitted by the QF, a price which may not exceed a utility's MDPU-approved ceiling price for the block of power released for bid.

(MDPU Order 84-276-B, August 25, 1986, Regulations, p. 2)

The goal of the *bidding* process is to attract, evaluate, and select QFs on a competitive basis that wish to sell energy and capacity on a long-term basis at a fixed price. Every 12 months, utilities

are required to issue a MDPU-approved request for proposals (RFP). The RFP specifies a supply block of power with a maximum or "ceiling" price that is based on the utility's projected cost of supplying that power for a 20-year planning period. Each QF receives a score based on economic and non-economic characteristics and is ranked competitively with other submitted bids. Winning proposals receive long-term contracts at the price bid by the QF. The net present value of the bid price cannot exceed the net present value of the utility's ceiling price. A utility RFP must list the available supply block and ceiling price schedule, explain the competitive bidding and ranking procedure, and specify any minimum or maximum threshold values that QFs must meet in order to be considered. The RFP must also include oil and gas projections, a general inflation rate and other price escalation measures, the assumed discount rate, a methodology for QFs to estimate their interconnection costs, and any pricing rules or constraints a utility may use to compare bids (Ibid., pp. 28-29).

QFs must furnish a price in their bid, the capacity amount of energy the project is expected to generate over time, and a pricing formula (e.g., levelized, front-loaded, floor rate with escalating pricing, derived heat rate, etc.). In addition, the QF will submit information on estimated capacity factor, availability, dispatchibility, interruptibility, voltage control, and the interconnection location.

The parameters and criteria to evaluate QF proposals are set by each utility and are subject to MDPU approval. These must be clearly stated in the RFP. The utility is charged with selecting those QFs that best meet the parameters and criteria. The highest ranking proposals are awarded standard contracts until the supply block is filled. Some suggested criteria include length of contract period, proposed in-service date, power production during on-peak and off-peak times, ease of acquiring siting and environmental permits, type of project, extent of project development, status of project financing, financial strength, financial risk, and amount of security deposit. Performance requirements are not allowed unless the QF agrees to be operated under "economic dispatch" (Ibid., pp. 28-35).

All QFs must deposit $15 per kW of capacity in cash, a letter of credit, or other form of payment acceptable to both the utility and the QF. If the QF is cancelled, withdrawn, or otherwise terminated after the proposed in-service date, the utility will receive the entire security deposit, plus any accumulated interest. If the project reaches commercial operation on or before the in-service date, the QF receives the deposit and any interest back. If the project is cancelled before the proposed in-service date, the utility and the QF will proportionally split the deposit, based on the amount of time elapsed between signing of the contract and the cancellation of the project.

If payments to QFs exceeds the ceiling price schedule for any period of time (e.g., front-loaded payment plans), the QF must provide a means of financial security. At a minimum, the QF must make the utility a lien holder of its power production facility (Ibid., pp. 34-35).

Interconnection Requirements

Utilities are required to interconnect with QFs at the QF's request. An initial inspection of the QF site and a preliminary estimate of the interconnection costs will be provided at the expense of the utility. The incremental costs of interconnection, including detailed cost estimates, engineering studies, and improvements or additions to the utility's transmission and distribution system, are the QF's responsibility. QFs selling under short-term rates can amortize their interconnection costs over three years at an interest rate based on the utility's averaged weighted cost of capital.

The monthly tariffs charged by utilities to QFs are subject to MDPU approval. The tariffs must include standard rates for commonly-used interconnection equipment based on invoice costs, monthly charges for meter maintenance and readings, and carrying charges for interconnection costs and utility-owned metering equipment (Ibid., pp. 5-9).

Back-Up Rates and Service

Utilities are required to supply back-up power to QFs under rate schedules applicable to all customers with similar load characteristics. Should the QF be eligible for more than one rate schedule, the QF may select the rate schedule.

QFs and utilities may choose to negotiate their own back-up rates and contracts (Ibid., pp. 38-39).

Wheeling QF Power

Utilities must wheel QF power to another utility upon the request of the QF. If wheeling QF power requires improvements or changes to the utility's transmission and distribution system, the QF must bear its share of the costs of such changes (Ibid., p. 10). The allocation of such costs is to be determined on a case-by-case basis (Ibid., p. 18).

QFs are not allowed to sell power at retail rates or to wheel power to an affiliated party (M.G.L. Chapter 164, Section 1).

Transmission Availability and System Upgrades

A shortage of transmission capacity is beginning to appear in New England, most severely impacting Massachusetts in the northeast region. These limitations, for example, can affect the ability of cogenerators in Maine to sell electricity to Massachusetts companies (Paul F. Levey, Chairman, DPU, "Rush-Hour Congestion on Electricity Highways," *Boston Globe*, September 2, 1986).

Performance Requirements and Security Payments

There are no specific performance criteria that QFs are required to meet. However, as-available buy-back rates are time-differentiated (see "Buy-Back Rates"), and QFs are required to post a security deposit if they are taking part in the bidding procedures that may be partially or wholly forfeited should the project not come on-line.

NEVADA

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I. BACKGROUND

Nevada is the second fastest growing state in the country and imports over 90% of its fuels (Testimony of Stephen Wiel, Nevada Public Service Commission, before the Subcommittee on Energy Development and Applications, House Committee on Science and Technology, p. 4, and *The Nevada Alternative Energy Source Book*. Carson City: Governor's Office, Office of Community Services, 4th edition, 1986, p. 1). Over $2 billion is expended on energy in Nevada annually, or $2,000 for every man, woman, and child. Unlike much of the country, neither of the major utilities has surplus capacity, although Sierra Pacific is somewhat capacity rich due to firm and economy purchases that comprise over 50% of its energy.

II. STATE UTILITY REGULATORY AUTHORITY

The Nevada Public Service Commission (NPSC) has jurisdiction over the following:

- Implementation of PURPA
- Plant siting and licensing
- Utility cost recovery
- Utility resource plans

The NPSC shares some jurisdiction on permitting with the State Environmental Protection Division of the State Department of Conservation and Natural Resources, which issues air quality and most other state environmental permits (Personal Communication, Thomas Henderson, Nevada Public Service Commission, October 10, 1986).

III. REGULATION OF UTILITY ACTIVITIES

Resource Planning

In 1983, the Nevada Legislature enacted the Utilities Resource Planning Act, requiring the two largest electric utilities to biennially submit resource plans for approval by the NPSC. Cogeneration, conservation, load management, solar, geothermal, wind, and hydro must be equally considered with conventional fuels when utilities desire additional capacity. Furthermore, the NPSC issued General Order 43, requiring utilities to conduct a cost-benefit analysis comparing non-traditional to traditional supply options when requesting additional capacity. No parameters have been set, however, on how to perform such a study.

From the study, the utilities present a plan outlining long-term revenue requirements at the least-cost to Nevada ratepayers (NARUC Survey Response). The law requires utilities to choose generating options that have the lowest present value of revenue requirements. The regulation also requires utilities to submit plans outlining capacity needs 20 years into the future, with two

year "action plans" outlining commitments and expenditures needed during the biennium prior to the next resource plan filing (Personal Communication, Thomas Henderson, Nevada Public Service Commission, October 7, 1986).

Under the first resource plan in 1984, the two utilities dedicated 98 MW, or 19% of their expected capacity needs to conservation and renewables. So far, the utilities emphasize conservation and geothermal the most (Testimony of Stephen Wiel, Nevada Public Service Commission, before the Subcommittee on Energy Development and Applications, House Committee on Science and Technology, p. 4). In renewables, Nevada Power is conducting a wind energy study near Las Vegas, testing a solar thermal parabolic dish system, and participating on the project review committees of the Solar One central receiver project near Barstow, California. Sierra Pacific is buying power from two pilot geothermal projects, two geothermal qualifying facilities, and a few small hydro and wind energy producers (Personal Communication, Thomas Henderson, Nevada Public Service Commission, October 7, 1986).

Sierra Pacific has been directed by the NPSC to pay the established avoided capacity and energy costs to QFs producing electricity by June 30th, 1987 that contribute to the first 35 megawatts of incremental capacity (NPSC modified order, Docket No. 85-1004 and 85-1005, August 26, 1986, p. 3). The NPSC will approve additional blocks of capacity for Sierra Pacific for the biennium beyond June 1987 after the NPSC acts upon Sierra Pacific's resource plan.

Power Plant Certification

A Utility Environmental Protection Act (UEPA) permit must be obtained before a power plant can be built. To acquire this permit, a regulated utility must provide evidence that:

- There is a need for the facility
- The facility will cause the least possible environmental impacts, in consideration of the state of the facility's technology and the status and costs of possible alternatives
- The facility meets all state and local laws and regulations

(NRS 704.890 and Laws of Nevada, Chapter 366, Section 6, p. 887).

In addition, the proposed facility must be included in an NPSC-approved utility resource plan, meaning the facility must pass least-cost tests as compared to other supply and/or demand alternatives (Personal Communication, Steve Tullis, Nevada Public Service Communication, November 7, 1986).

Cost Recovery

Utility payments to QFs are recovered through the "deferred energy mechanism," as long as the payments are at NPSC-approved rates (NPSC Docket No. 85-1004 and 85-1005, June 23, 1986, p. 30).

Utilities have been allowed to recover certain fees and dues for organizations such as EPRI; however, some have been partially disallowed as they were associated with certain projects considered irrelevant to the state of Nevada. These costs are expensed rather than added to the rate base (Personal Communication, Steve Tullis, Nevada Public Service Commission, November 7, 1986).

Research and Development Expenditures

The NPSC evaluates utility research and development expenditures on a case-by-case basis. The costs of Nevada Power's solar thermal parabolic dish test system, for example, were not approved for recovery by the NPSC (Personal Communication, Thomas Henderson, Nevada Public Service Commission, October 10, 1986).

Utility Diversification into Non-Regulated Businesses

Nevada utilities have established holding companies and subsidiaries to engage in real estate, banking, energy exploration, and other non-regulated activities. The NPSC is keeping a close eye on these activities but has not issued a formal ruling on this issue (Personal Communication, Steve Tullis, Nevada Public Service Commission, November 7, 1986).

IV. IMPLEMENTATION OF PURPA

Qualifying Facility Definition

Nevada does not depart from the FERC definition of a"qualifying facility."

Utility Ownership of QFs

No utility has established a QF subsidiary, so the NPSC has not had the opportunity to issue a formal ruling on this subject (Personal Communication, Steve Tullis, Nevada Public Service Commission, November 7, 1986).

Avoided Cost and Buy-Back Rates

Avoided cost rates are utility specific. Generally, short-term energy rates are based on a National Economic Research Associates computer model that simulates a utility's marginal operating costs using a peaker combustion turbine, estimated by the NPSC at $329/kW. For Nevada Power, the cost of capital, the capacity factor, line losses, carrying charges, and the cost of maintaining a 5% reserve margin all affect their short-term avoided energy rates. Sierra Pacific rates were determined using a similar methodology (NPSC modified order, Docket No. 85-1004 and 85-1005, August 26, 1986, Appendix B). Although it has been suggested this be changed to a six month period, all short-term avoided energy cost rates are scheduled for revision on a quarterly basis.

Capacity payment rates are available for QFs, but Nevada Power requires them to meet certain performance levels. Sierra Pacific allows capacity payments based on energy (kWh) output, as determined by the lowest amount of energy delivered in the previous 12 months (NARUC Response).

Long-term avoided cost rates have only been set for Sierra Pacific; Nevada Power's methodology was rejected by the NPSC in 1985. Sierra Pacific's rates are based on an avoided coal plant (NPSC Docket No. 85-1004 and 85-1005, June 23, 1986, p. 16). Long-term rates are revised every

odd year (Personal Communication, Thomas Henderson, Nevada Public Service Commission, October 10, 1986).

Levelized rates are not favored by the NPSC because of fear that QFs will be "loaned" money at utility and ratepayer risk. A proposed security deposit was rejected as unnecessary and burdensome. Instead, energy rates are indexed by coal component of the Producer Price index for energy, and the Handy-Whitman price index (total steam production plant category) for capacity (NPSC Docket No. 85-1004 and 85-1005, June 23, 1986, pp. 18, 33).

Standard Contracts

Standard contracts are available from both Sierra Pacific and Nevada Power. However, the contracts have never been formally approved by the NPSC. The Commission prefers to assure flexibility and to encourage negotiations between QFs and Nevada utilities. Long-term contracts are available in terms of 10, 15, 20, and 30 years (NPSC Docket No. 85-1004 and 85-1005, June 23, 1986, p. 20).

Interconnection Requirements

The QF pays all interconnection costs, including any necessary improvements to the transmission and distribution system. Utilities must offer a schedule of amortization for QFs for the value of the interconnection (Nevada Administrative Code 704.725).

Back-Up Rates and Service

At the present time, back-up power can be purchased by QFs at normal retail rates. A QF may purchase power independent of energy sales to the utility (Personal Communication, Steve Tullis, Nevada Public Service Commission, November 7, 1986).

Wheeling QF Power

No tariffs containing wheeling rates are available for QFs (NARUC Survey). However, some QFs are wheeling by contract. A 62 MW geothermal small power facility in Dixie Valley has a permit to build a transmission line to a California utility. A 16 MW geothermal facility located at Beowawe was wheeling 11 MW to California through the Sierra Pacific transmission system (Personal Communication, Thomas Henderson, Nevada Public Service Commission, October 10, 1986). This has recently been increased to the full 16 MW of generating capacity.

A potential future issue involves the ability of Nevada small power producers to export power to other states. State law allows Nevada utilities to recapture, after 13 years, a power-generating source if more than 50% of its generation is exported out of state (NRS 704.890 (6)).

Transmission Availability and System Upgrades

Transmission access for QFs is presently a problem. The power being wheeled to California from the 16 MW geothermal facility at Beowawe is now at the transmission system's capacity. One QF is building transmission lines to wheel to an out-of-state utility (see "Wheeling QF Power").

NEW JERSEY

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I. BACKGROUND

The combination of dependence on out-of-state power, escalating plant construction costs, and the lack of domestic coal, natural gas, and oil resources contributed to New Jersey having one of the highest retail electricity rates in the country--12¢/kWh for the residential sector as of July 1985 (New Jersey Department of Energy, *New Jersey Energy Master Plan 1985*, December 1985, p. 47). In 1984, out-of-state purchased power was the New Jersey's largest source of electricity in 1984 at 34.5%. Coal was next at 26.3%, followed by natural gas at 14.5%, nuclear at 13.2%, residual oil at 11.1%, and fuel oil at 1% (Ibid.). In a study published in December 1985, the New Jersey Division of Energy Planning and Conservation (NJDEPC formerly the Department of Energy) noted the rich potential for cogeneration and small power production in the state, then practically nonexistent. Since then, contracts for 1000-1500 MW of cogeneration have been signed by New Jersey utilities (Personal Communication, Mike Ambrosio, New Jersey Board of Public Utilities, November 5, 1986).

II. STATE UTILITY REGULATORY AUTHORITY

The NJDEPC has jurisdiction over utility resource planning and oversees the certificate of need process for new generating facilities. The New Jersey Board of Public Utilities (NJBPU) is responsible for setting retail electricity rates, implementing PURPA and regulating utility practices (Personal Communication, Mike Ambrosio, op. cit.).

III. REGULATION OF UTILITY ACTIVITIES

Resource Planning

The NJDEPC attempted to issue regulations requiring utilities to submit a plan to the NJDEPC and the NJBPU by mid-1986 covering competition between utility and non-utility generating facilities. The plans would have included data on methods of comparing the direct and indirect costs of electricity generation, system efficiency, reliability, and environmental impacts of utility and non-utility facilities. This action was stayed by the State Appellate Court, which

postponed a final decision until spring of 1987 (Personal Communication, William Potter, New Jersey Division of Energy Planning and Conservation, November 25, 1986).

The NJDEPC is required to publish an annual status report on cogeneration in New Jersey. At a minimum, the report includes data on the amounts of cogeneration planned, federally licensed, under contract, under construction, and in operation.

Power Plant Certification

A new source permit from the New Jersey Department of Environmental Protection is required for any utility-owned facility over 100 MW in capacity. The NJDEPC can dispute a NJDEP decision, upon which the Governor will appoint a third party as the final arbitrator (Personal Communication, William Potter, op. cit.).

Cost Recovery

The NJBPU examines utility cost recovery initiatives on a case-by-case basis. Payments made by utilities to QFs are recoverable, as are EPRI and EEI membership dues (Personal Communication, Mike Ambrosio, op. cit.).

Research and Development Expenditures

The NJBPU considers utility requests for recovering research, development, and demonstration expenditures on a case-by-case basis (Personal Communication, Mike Ambrosio, op. cit.).

Utility Diversification into Non-Regulated Businesses

The NJBPU allows utilities to set up holding companies or subsidiaries to engage in other business ventures if separate accounting practices are maintained. Currently, two utilities are involved in real estate development (Personal Communication, Mike Ambrosio, op. cit.).

IV. IMPLEMENTATION OF PURPA

Qualifying Facility Definition

The NJBPU does not depart from the FERC definition of a "qualifying facility."

Utility Ownership of QF Facilities

The NJBPU allows utilities to set up QF subsidiaries (Personal Communication, Mike Ambrosio, op. cit.).

Avoided Cost and Buy-Back Rates

QFs between 100 kW and 1 MW are eligible for avoided energy payments that the NJBPU bases on the power purchase rate from the Pennsylvania-New Jersey-Maryland (PJM) power pool. A

10% premium is added in recognition of the "societal benefits" QFs provide, e.g., solid waste reduction, or minimal environmental impacts. QFs may choose to base electricity sales on a time-of-day or hour-by-hour basis.

Avoided capacity payments are determined by estimating the fixed cost of adding a combustion turbine peaking unit or by the PJM pool penalty a utility must pay if short on capacity. To be eligible for capacity payments, a QF has to be over 100 kW in capacity and supply capacity on a two-hour test basis twice a year (New Jersey Board of Public Utilities, Docket #8010-687, October 14, 1981, p. 4). The level of payments is determined by calculating the average capacity provided by the QF during the utility's on-peak period.

QFs below 100 kW must use a time-of-day basis, while QFs over 1 MW must negotiate directly with the utility, subject to NJBPU approval (Ibid., p. 5). Should negotiations stall, a QF may use the avoided cost rate (New Jersey Board of Public Utilities, Docket #8010-687, Order of Clarification, December 7, 1983, p. 2). If a QF is located in close proximity to its end-use, the NJBPU may grant the QF avoided transmission or distribution payments in the buy-back rate.

Utilities must file annual, long-run avoided cost studies to the NJBPU (New Jersey Board of Public Utilities, Docket #8010-687, op cit, p. 4). These studies must include the methodology utilities use to estimate their energy costs, their projections of future fuel prices, the annual projected load in MW and total energy demand in MWh over 20 years, the estimated source and cost of electricity from that source for each year of the 20 year period (e.g., nuclear, coal, oil, steam, hydro, purchased energy, etc.), and the utility's plan for adding plant by amount and type, amounts of energy the utility plans to purchase, and the amount of capacity it will retire (New Jersey Board of Public Utilities, Docket #8010-687, Order of Clarification, op. cit., p. 3). The NJBPU may adjust the energy and capacity payment provisions based upon this utility information (New Jersey Board of Public Utilities, Docket #8010-687, op. cit., p. 4).

Standard Rates

The NJBPU is current negotiating with New Jersey utilities to offer QFs standard contracts, referred to as standard price methodology or standardized pricing. Presently, one utility, Jersey Central Lighting and Power (JCP&L), has standardized pricing available for QFs if the QF provides the following:

- A FERC certificate affirming QF status.
- A statement describing the project, including a preliminary project design and construction schedule, expected project operation start-up and annual energy delivery.
- A letter of intent promising site control and maintenance.
- Evidence that reliable and satisfactory fuel supplies are expected over project's anticipated life and for the assumed level of energy production.
- A plan for securing all required licenses and permits.
- Proof of the project's financial feasibility, along with a preliminary financing plan.

The amount of levelization allowed and the length of time of the standard price methodology varies by technology, depending on capital intensiveness and/or vulnerability to rapid changes in fuel costs (New Jersey Board of Public Utilities, Docket No. 8010-687, "Standard Price Methodology for Purchase of Energy by JCP&L from Qualifying Facilities in New Jersey", Attachment A, August 6, 1986, pp. 3-4). Up to 70% of the avoided cost can be levelized, and standard pricing lengths between 10 and 30 years (Ibid., p. 19).

JCP&L's standard contract does not include provisions related to dispatchibility; interconnection, operation, and integration requirements; energy delivery incentives and penalties; technologies not covered in the standard price methodology (e.g., wind and solar); and any other terms or conditions not part of the JCP&L's standard contract. Any negotiated agreements between a utility and a QF must receive NJBPU approval before they can take effect.

JCP&L may suspend its standard price methodology and issue new provisions to reflect significant changes in avoided costs. NJBPU approval must be obtained before such a suspension would take effect; current agreements would not be affected (New Jersey Board of Public Utilities, Docket No. 8010-687, August 6, 1986, p. 12).

A signed offer between a QF and JCP&L will expire unless the QF signs a full contract within 1 year. The contract will include preliminary target dates for commencing project construction and operation and dates that must be met for the signed offer to remain effective. Dates that are missed, however, are not reasons to amend the contracted payment schedule or length of the contract. If the actual year of operation is earlier than is declared in the contract, the payments take effect upon project operation rather than the contract date (Ibid., p. 13).

At the end of 1986, or when JCP&L has signed 600 MW above what was on-line as of May 1, 1986, JCP&L's standard price methodology provisions will be reviewed (Ibid., p. 10). As of mid-November of 1986, JCP&L had signed 560 MW of QFs to contracts, almost all fossil-fired cogeneration (Personal Communication, William Potter, Division of Energy Planning and Conservation, November 25, 1986).

Interconnection Requirements

As part of their application to a utility for interconnection, each QF must submit facility plans and specifications, a diagram of system protective equipment, instruction manuals for all of the protective equipment, internal wiring illustrations and specifications of protective components, generator data for examining fault contributions and load current flows, and any ratings of protective equipment not mentioned in the instruction manuals. The utility must respond affirmatively or negatively within 30 days of receiving a complete application (New Jersey Board of Public Utilities, Docket #8010-687, op. cit., p. 6).

Interconnection costs for a QF are determined by estimating the difference between the costs to the utility for receiving QF energy and utility costs for supplying back-up and stand-by energy to the QF. The former includes the cost of meters, overhead service connections and distribution facilities to meet load, while the second comprises relaying and safety equipment and any additional service lines and distribution facilities needed to receive QF power or supply power to the QF (Ibid., p. 7).

The QF must maintain constant and compatible output voltage with the utility system, provide and maintain automatic synchronization with the utility system, that the QF's total harmonic distortion be less than 5%, and the cost of adding additional equipment or devices the utility considers necessary be the QF's financial responsibility. The QF will also install control devices

to isolate the utility from the QF's facility in case of a fault on the QF's equipment, a fault on the utility system, an abnormal voltage or frequency, unusual power factor, the lack of automatic synchronization with the utility system, total harmonic content over 5%, or the loss of a phase or the presence of an improper phase sequence.

Utilities may inspect and test the QF's facility. Also, the QF must conduct and document maintenance of their facility. The utility may disconnect the QF if inspection, testing, and maintenance provisions are not met (Ibid., p. 8). The QF must allow access to utility representatives for installation, inspection, and maintenance of the utility's metering equipment. The QF will also absolve the utility from any liability or claim for damage to the QF's or utility's equipment or personnel as a consequence of the presence, operation, maintenance, or removal of the QF's installation.

Utilities may disconnect the QF if:

- The utility cannot back down its own generating capabilities to accept power without endangering the utility or PJM system. The utility must provide 90 days notice before taking this action.
- Distribution or transmission system capacity is not available for QF power. No utility notice is required for this provision.
- A utility system emergency occurs. Again, no utility notice is required.

(Ibid., p. 9).

Wind facilities may not have a wind generator, tower, or other equipment that may contact or land upon utility lines or equipment in the case of a structural failure.

Some relief from interconnection fees is available to residential or small renewable energy systems. After the NJBPU issued its PURPA implementation order in 1981, the Public Service Electric and Gas Company (PSE&G) waived the monthly service charge for the first 10 small wind systems; JCP&L will not charge small energy producers a monthly interconnection charge should the QF's energy sales be less than the monthly interconnection fee; and Atlantic City Electric (ACE) has excluded any small QF from the fee if the QF allows ACE to instrument the facility (Ibid., p. 10).

Back-Up Rates and Service

Utilities may assess QFs a demand charge and a monthly tariff, based on an average 15% out-of-service time. These changes average between $1.00 and $3.00 per kW. If stand-by, back-up, or interruptible power is needed by the QF, the utility charges the QF retail rates, based on the QF's customer classification. Should the QF have an unscheduled outage or has scheduled an outage with a utility, the QF will not be subject to the demand charge. The monthly tariff, though, still is in effect (Personal Communication, Mike Ambrosio, op. cit.).

New Jersey utilities have agreed to continue providing back-up power, supplemental power, maintenance power, and interruptible power under fair and non-discriminatory rates to all QFs, regardless of who owns, finances and/or operates the QF, despite a recent FERC decision that allowed utilities to not provide third-party financed and/or owned QFs with power (In the matter of P.R.E.P.A. [Alcon], FERC Docket No. QF 84-147) (Personal Communication, William Potter, op. cit.). (FERC subsequently reversed its decision.)

Wheeling QF Power

In general, the NJBPU does not feel it has the jurisdiction to require wheeling or to set wheeling rates. However, the NJBPU is negotiating with PSE&G to wheel QF power to JCP&L at a rate of approximately 1.5-3 mills/kWh, provided FERC does not disapprove. The rate includes a factor for line losses (Personal Communication, Mike Ambrosio, op. cit.).

Transmission Availability and System Upgrades

NJBPU's wheeling rate for PSE&G covers any costs required to upgrade or build new transmission and/or distribution equipment (Personal Communication, Mike Ambrosio, op. cit.).

Performance Requirements and Security Payments

Unless such requirements are negotiated between a QF and a utility, there are no QF non-performance provisions required in New Jersey.

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I. BACKGROUND

The predominant source of electricity for New York in 1985 was hydro, generating 24% of all electricity. It was followed closely by petroleum at 23%, nuclear power at 22%, coal at 17%, and natural gas at 14% (U.S. Energy Information Administration, *Electric Power Annual*, July 1986).

II. STATE UTILITY REGULATORY AUTHORITY

The New York Public Service Commission has authority to set and review utility electricity rates, to implement PURPA, and to review utility cost recovery applications. The Department of Environmental Conservation has jurisdiction over environmental protection and control issues, while the New York State Board of Electric Generation Siting has responsibility for siting and licensing issues (Personal Communication, Eva Lubeck, New York Public Service Commission Authority, September 11, 1986).

III. REGULATION OF UTILITY ACTIVITIES

Resource Planning

Excluding Long Island, the state of New York expects to have enough electric capacity to meet demand for the next 15 years. Alarmed by the rapid escalation in capital costs of large central station facilities and drastic upswings and downswings in fuel prices and load growth, the New York Public Service Commission (NYPSC) is currently evaluating possible changes to the state's resource planning. The NYPSC will consider whether current state policies give utilities enough incentives to use load management, conservation, on-site generation and alternative energy sources; what the advantages and disadvantages are of constructing new generating plans as opposed to encouraging conservation, load management, on-site generation, and alternative energy sources; the advantages and disadvantages of stimulating competition between utility and non-utility electricity suppliers; and the financial impacts of these issues (NYPSC, Case 29409, August 15, 1986, pp. 2-3).

Power Plant Certification

The New York Board of Electric Generation Siting and the Environment has authority to certify fossil-fueled facilities 50 MW or more in capacity. A permit from this board supersedes all other

permits. An application for a new generating facility has not been filed since the late 1970s (Personal Communication, Harvey Arnett, New York Public Service Commission, November 18, 1986).

Cost Recovery

The NYPSC evaluates utility cost recovery initiatives on a case-by-case basis, using a "prudently incurred" standard.

Research and Development Expenditures

Utility research and development expenses and financial support of organizations, such as the Electric Policy Research Institute (EPRI), are considered on a case-by-case basis. EPRI dues are generally approved (Personal Communication, Harvey Arnett, New York Public Service Commission, September 12, 1986).

Utility Diversification into Non-Regulated Businesses

New York utilities can form wholly-owned subsidiaries for QF development that are not subject to NYPSC regulations (see "Utility Ownership of QFs"). The Orange and Rockland utility has, with NYPSC approval, established a subsidiary to engage in real estate (Personal Communication, Frank Berak, New York Public Service Commission, November 19, 1986).

IV. IMPLEMENTATION OF PURPA AND RELATED ISSUES

QF Definition

New York does not depart from QF definitions outlined in FERC's PURPA regulations.

Utility Ownership of QFs

Utilities are allowed to establish subsidiaries to buy or sell power, provided that the two organizations operate independently, that separate books be maintained, that a tariff rate be filed with the NYPSC should transmission facilities or other utility services be required, and that the utility shall not promote the subsidiary or provide the subsidiary with proprietary information (New York Public Service Law, Article 4, Section 66c, 1982, pp. 41-42). All business actions between a subsidiary and the utility must be filed with the commission within 30 days.

Avoided Cost and Buy-Back Rates

New York has set a minimum buy-back rate at 6¢/kWh for utility purchases of electricity from QFs built after June 26, 1980 (New York Public Service Law, Section 66c, 1982, p. 41). Levelized and front-loaded rates are available. Short-term and long-term, time-differentiated rates can also be used. QFs that do not produce power during peak demand will generally not receive a capacity payment (NARUC Response).

For QFs desiring a long-term rate, separate buy-back provisions exist for hydro and non-hydro facilities and, within the latter, for small (under 5 MW), medium (5-20 MW) and large (over 20 MW). Hydro facilities have four options to choose from:

- Fixed payments based on projected long-run avoided costs projections can obtained for up to 15 years. The parties can negotiate terms for periods longer than 15 years, with the understanding that the NYPSC will allow facilities to receive full avoided cost tariff rates. The NYPSC will review these contracts on a case-by-case basis.

- Contracts may be front-loaded for a specified period lasting no longer 15 years. Payments later in the contract must offset the higher payments made at the beginning of the contract. Moreover, protective measures must be included to protect ratepayers from default by the hydro developers. These include: a cap on the amount that payments may exceed avoided costs, with interest on the amount above avoided costs; security provided by the developer for payments above the avoided cost, and the responsibility of the developer to assume liability for any negative tax impacts on the utility for making payments in excess of avoided costs.

- Levelized payments are available for up to 15 years. Similar to front-loaded contracts, the higher payments in the initial stages of the contract will be recouped by lower payments made at the conclusion of the contract. The contract must include the security provisions required for front-loaded contracts.

- Hydro developers that include storage features (pondage) can receive payments in excess of the projected annual average avoided cost for up to 15 years. Power must be supplied during peak demand in order to be eligible for this option.

(New York Public Service Commission, Opinion No. 86-8, March 27, 1986, pp. 56-58).

Long-term avoided costs are available for QFs wanting fixed payments for a period of time. Because of transmission capacity limitations, avoided costs are set on a statewide basis until all transmission capacity is exhausted. At that point, the state would be divided into three regions for determining long-term avoided cost rates.. Energy payments are calculated by running a computer analysis of total estimated energy production costs using three assumptions: projected demand, projected demand plus 50 MW, and projected demand minus 50 MW. The figures are then divided by 100 MW and multiplied by the number of hours in a year.

Long-run capacity payment rates are based on estimating the probability of an annual loss of load due to lack of generation compared to the loss of load in the year when capacity will have to be added. The resulting ratio is then multiplied by the annual cost of a natural gas peaker facility. This gas peaker unit is considered the avoided unit until 1995. At that point, the avoided capacity becomes a combination of the gas peaker unit and a deferred 600 MW coal plant (Personal Communication, Harvey Arnett, New York Public Service Commission, November 18, 1986).

The NYPSC biennially updates their long run avoided cost estimates and the methodology that supports it, and annually updates the assumptions surrounding inflation, load growth, and oil costs. In October of 1986, the NYPSC issued their long-term projections for inflation rates, load growth, and the price of oil. The NYPSC staff have recommended that the long-run avoided cost estimates be revisited (Personal Communication, Bob Whitaker, New York Public Service Commission, October 27, 1986).

Non-hydro developers receive different long-run avoided cost payments and contracts depending on their size. Small developers under 5 MW are eligible for fixed, year-by-year payments at the long-run avoided cost estimate for up to 15 years (NYPSC Opinion 86-8, op. cit., p. 59).

Medium, non-hydro developers (5-20 MW) can receive the same pricing option as small facilities, except the fixed payments for years 11 through 15 will be revised in year 11 to reflect the most recent long-run avoided cost estimates.

Large, non-hydro developers (>20 MW) can also receive fixed payments, but they are updated in years six and eleven to reflect current long-run avoided cost estimates. Two other options are also available. Utilities are required to offer long-run, fixed annual payments equal to the capacity cost estimates. Variations in energy payments are pegged to current avoided energy costs and may be revised using independent fuel markets. The index used and the contract length are decided on a case-by-case basis (Ibid., p. 59). The second option would allow fixed payments above or below the long-run avoided costs estimates, with revisions allowed every 5 to 10 years. The actual payments used would also be set on a case-by-case basis.

Standard Contracts

The NYPSC has created proceedings to establish long-run standard contracts that include the long-run, avoided cost provisions used for determining buy-back rates for hydro and non-hydro developers (Ibid., p. 61). A decision is expected in 1987 (Personal Communication, Harvey Arnett, New York Public Service Commission, November 18, 1986). Presently, a QF wanting a long-run contract must negotiate directly with the utility, with the NYPSC acting as an arbitrator should disputes arise (Personal Communication, Bob Whitaker, op. cit.).

Interconnection Requirements

QFs are responsible for paying utility interconnection costs, including but not necessarily limited to the following:

- Metering costs surpassing those increased to supply firm service to customers.
- Yearly carrying charges on equipment required for interconnection to allow the utility to recover tax and operation and maintenance costs.
- Engineering and feasibility study costs and distribution system improvements done for the single purpose of interconnecting a QF.

Utilities do not have to accept installment payment plans by the QFs to pay for interconnection costs. Any such arrangement must include charges for interest (New York Public Service Commission, Opinion No. 82-10, May 12, 1982, p. 135).

Back-Up Rates and Service

Five conditions govern the setting of back-up and supplemental power rates:

- Reactive power charges are permitted if they are also charged to firm customers.

- System-wide, contract demand charges on a per-kW basis are allowed to recover improvements made to the distribution system to serve a QF.

- User-sensitive charges for service during class and system peak demands System peak-related charges are recovered at peak-period, per-kWh or ratcheted per-kW rates. Costs from class peaks are recovered in peak-period, ratcheted per-kW charges.

- Back-up service cannot be taken at greater than 10% of the load factor relative to the contract demand.

- The amount of contract demand may be negotiated annually.

(New York Public Service Commission, op. cit., p. 133).

In all cases, a QF may simply purchase back-up and supplemental power at retail rates (Personal Communication, Harvey Arnett, New York Public Service Commission, November 18, 1986).

Wheeling QF Power

The NYPSC is unsure of its jurisdiction in this area and therefore has not set rates (Ibid., p. 135). However, QFs have indicated willingness on the part of some utilities to wheel QF power (NARUC Response). Direct sales from a QF to an end-user are allowed, as long as the power or capacity is sold at or less than 1 mile from the project site (Personal Communication, Harvey Arnett, New York Public Service Commission, September 12, 1986).

Transmission Availability and System Upgrades

Improvements to the transmission and distribution system are generally assumed to have system-wide benefits, with the costs being recovered through the rate base. If it can be shown to the NYPSC that such transmission upgrades will benefit only QFs, then QFs must pay the direct costs or else negotiate a reimbursement plan with the utility (Personal Communication, Harvey Arnett, New York Public Service Commission, November 18, 1986).

Performance Requirements and Security Payments

Medium and large non-hydro facilities (>5 MW) must agree to performance standards if they desire long-term, avoided cost contracts. This is to be negotiated and decided on a case-by-case basis (NYPSC, Opinion No. 86-8, op. cit., p. 60).

TEXAS

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I. BACKGROUND

Until recently, almost all electric capacity in Texas was derived from oil- and gas-fired facilities. These facilities accounted for 95% of statewide electric capacity as recently as 1975. Nuclear, lignite and coal facilities have increased dramatically since then, decreasing dependence on oil and gas to 70% in 1985, with a further drop to 53% expected by 1995. Lignite and coal represented 12% and 15.2% of electric capacity in 1985, respectively. They are projected to increase in 1995 to 20.3% and 15.5%, respectively. Nuclear is only just coming into Texas' electricity mix, with four large nuclear plants expected to come on-line by 1995, when these plants would account for 7.2% of Texas statewide capacity (Commissioner Dennis Thomas, Texas Public Utility Commission, Testimony before the U.S. Senate Committee on Energy and Natural Resources, June 5, 1986, p. 7).

Since 1980 Texas has experienced tremendous development in oil- and gas-fired cogeneration. Over 3100 MW of cogeneration was on-line by the end of 1985, with another 6265 MW in various stages of construction and/or licensing. Should all the projected cogeneration come on-line, it would constitute 20% of Texas generating capacity (Thomas PURPA Testimony, op. cit., p. 7). The Texas Public Utility Commission (TPUC) is counting on cogeneration to levelize the costs of assimilating the four nuclear plants into the rate base by 1995, and allow time to evaluate the economic and environmental impacts of further exploiting Texas' lignite reserves (Thomas PURPA Testimony, op.cit., p. 22).

II. STATE UTILITY REGULATORY AUTHORITY

The Texas Public Utilities Commission has jurisdiction over the following:

- Setting utility wholesale and retail electric rates
- Approving/declining utility cost recovery initiatives
- Overseeing utility resource and capacity expansion plans
- Issuing "certificates of convenience" for new power plants

(Personal Communication, Kent Saathoff, Texas Public Utility Commission, Austin, TX, September 11, 1986)

III. REGULATION OF UTILITY ACTIVITIES

Resource Planning

The TPUC requires utilities to consider least cost alternative to meet energy needs, including cogeneration and conservation (Personal Communication, Kent Saathoff, Texas Public Utility

Commission, Austin, TX, September 11, 1986). To date, resource plans have been developed and implemented by the state's utilities. Several consumer, environmental, and business groups want utilities to better document costs in these plans and petitioned the TPUC on September 30, 1986, to require utilities to provide specific assessments for conventional and non-conventional options.

In addition, the petitioners requested that the Commission hold an annual workshop for utilities to discuss forecasting, end-use data collection, and supply and demand integration planning ("Texas Groups Want Rate Shock Protection," *PURPA Lines*, Vol. 2, No. 20, October 13, 1986, pp. 1-2). The TPUC is expected to rule on the petition in the near future.

Power Plant Certification

Utilities cannot receive a "certificate of convenience" to build a new, central station facility unless it can prove to the TPUC's satisfaction that power or capacity cannot be purchased from QFs or QF development is not the preferred alternative (NARUC Response).

Cost Recovery

A "certificate of convenience" must be issued by the TPUC before the construction of a demonstration or commercial facility can proceed. As of yet, no major commercial or demonstration renewable electric facilities have been built by a TPUC-regulated utility. Consequently, no utility has applied to recover construction or facility costs through the rate-making process. However, a 300 kW, grid-connected demonstration photovoltaic facility constructed by City of Austin Electric, a municipal not regulated by the TPUC, is due to commence operations by the end of 1986 in Austin (Personal Communication, Kent Saathoff, Texas Public Utility Commission, Austin, TX, September 11 and October 30, 1986).

Research and Development Expenditures

Internal research and development (R&D) expenditures and EPRI membership dues are reviewed on a utility-specific, case-by-case basis. Generally, these costs are allowed into the rate base (Personal Communication, Kent Saathoff, Texas Public Utility Commission, Austin, TX, September 11, 1986).

Utility Diversification into Non-Regulated Businesses

Two utilities have established subsidiaries: Houston Lighting and Power is involved with a television cable company, and Southwest Public Service has started an engineering consulting service. The TPUC has approached this issue with caution, evaluating each petition on a case-by-case basis (Personal Communication, Kent Saathoff, Texas Public Utility Commission, November 17, 1986).

IV. IMPLEMENTATION OF PURPA

QF Definition

Texas does not differ from the FERC definition of a "qualifying facility."

TEXAS

Utility Ownership of QFs

There is no statute or ruling directly prohibiting utilities from establishing subsidiary companies to own and/or operate QF projects. The present oversupply of electric capacity has acted as a deterrent so far: Only one utility--Texas-New Mexico--has a cogenerator subsidiary (Capital Cogen). The TPUC is concerned enough, though, to be watching closely for any future developments (Personal Communication, Kent Saathoff, Texas Public Utility Commission, Austin, TX, September 11, 1986).

Avoided Cost and Buy-Back Rates

The TPUC sets avoided costs for each utility based on the next unit of capacity the utility intends to construct. In most cases, this is a lignite coal facility (Thomas PURPA Testimony, op. cit., p. 2). Rates are revised every two years, along with terms and conditions applicable to each utility.

The avoided cost rates are meant to be a "ceiling" not to be exceeded. The approach of the TPUC is market-oriented; therefore, qualifying facilities (QFs) with projects over 100 kilowatts (kW) in capacity must negotiate directly with a utility (NARUC Response). With the present surplus of electricity in Texas, negotiated QF-utility avoided cost rates are 7-24% below the avoided costs rates (Thomas PURPA testimony, p. 2).

Standard Contracts

For QF projects below 100 kW in capacity, standard contracts can be obtained. The TPUC sets terms and conditions for each utility, based usually on a percentage of each utility's fuel cost (Personal Communication, Kent Saathoff, Texas Public Utility Commission, Austin, Texas, September 11, 1986).

For QF projects over 100 kW in capacity, contracts must be negotiated directly with the utility. Therefore, prices and terms will vary (NARUC Response).

Capacity and energy payments are available for "firm" QFs, i.e., those QF developers with a signed contract to deliver a specified amount of energy at particular times. For "non-firm" QFs (e.g., wind), only energy payments are available. For both capacity and energy payments, terms and conditions are up to the utility and the QF. Houston Lighting and Power (HL&P) pays a minimum capacity payment of $3/kW per month to QFs that have not signed a contract with HL&P. Docket proceedings are under way under application from HL&P to eliminate that provision, and it is likely it will be eliminated (Personal Communication, Kent Saathoff, Texas Public Utility Commission, Austin, TX, September 11, 1986).

Renewable QFs and municipal solid waste (MSW) projects are accorded special treatment and must be considered first when a utility requires additional capacity or energy (Thomas PURPA Testimony, op cit, p. 9). In practice, renewable QFs have not been economical under state avoided cost rates, so this preference is without effect (Personal Communication, Kent Saathoff, Texas Public Utility Commission, Austin, TX, September 11, 1986).

Interconnection Requirements

Utilities must interconnect with QFs, unless the utility comes under the jurisdiction of the Federal Power Act (Kent Saathoff, "The Current Status of Cogeneration at the Public Utility Commission of Texas," *Productivity Through Energy Innovation*, The Great PG&E Energy Expo 1986, Oakland, CA, April 30-May 2nd, 1986, pp. 585-86). In practice, no utility has refused to interconnect with a QF (Personal Communication, Kent Saathoff, Texas Public Utility Commission, Austin, TX, September 11, 1986). Interconnection costs must be paid by the QF.

Utilities may disconnect from QFs if the cost of purchasing QF-generated power would exceed the utility's cost of generating the power itself. The utility can also cease QF energy or capacity purchases if not doing so would cause or contribute to a system emergency (Kent Saathoff, "The Current Status of Cogeneration at the Public Utility Commission of Texas," *Productivity Through Energy Innovation, The Great PG&E Energy Expo 1986*, Oakland, CA, April 30-May 2nd, 1986, op. cit., p. 586).

Back-Up Rates and Service

Back-up power, if needed by the QF, must be provided by the utility (Kent Saathoff, "The Current Status of Cogeneration at the Public Utility Commission of Texas," op. cit., p. 585-86). Reversible meters must be supplied to renewable QFs below 50 kW in capacity. Back-up rates are set by the TPUC and are utility-specific (Personal Communication, Kent Saathoff, Texas Public Utility Commission, Austin, TX, September 11, 1986).

Wheeling QF Power

Utilities must wheel QF capacity or energy to another utility if requested to do so by a QF. The receiving utility must purchase the power or energy, and the wheeling utility will receive financial compensation (Kent Saathoff, "The Current Status of Cogeneration at the Public Utility Commission of Texas," op. cit., p. 585). No renewable energy is currently being wheeled, although a biomass facility developed by Valley View Energy Corporation is scheduled to wheel electricity to Austin in 1987 (Personal Communication, Kent Saathoff, Texas Public Utility Commission, Austin, TX, September 11, 1986). Retail sales or wheeling between QFs are not allowed by non-renewable QFs; however, renewable QFs under 10 MW can sell electricity to end-users under contract without receiving TPUC approval (Personal Communication, Kent Saathoff, Texas Public Utility Commission, Austin, TX, September 11, 1986).

Transmission Availability and System Upgrades

Utilities are required to construct additional transmission facilities, if needed, but may be reimbursed by QFs if it can be shown that the transmission facilities are only for the benefit of QFs (Thomas PURPA Testimony, op. cit., p. 13). Currently, over 1000 MW of cogeneration power is being wheeled from the Gulf Coast, straining regional transmission capabilities. A state legislative committee has recommended expediting transmission licenses in the area, and the TPUC is currently conducting a federally-funded study on the issue of future transmission needs (Personal Communication, Kent Saathoff, Texas Public Utility Commission, Austin, TX, September 11, 1986).

QF Non-Performance Liability

The TPUC has not articulated any statewide policy on this issue, preferring to leave it to negotiations between utilities and QFs (Personal Communication, Kent Saathoff, Texas Public Utility Commission, November 17, 1986).

WISCONSIN

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I. BACKGROUND

About 70% of Wisconsin's electricity comes from coal, with nuclear supplying 25%, hydro 4%, and oil and gas 1% (Personal Communication, David Schoengold, Wisconsin Public Service Commission, October 1, 1986). A Wisconsin Public Service Commission (WPSC) goal is to meet the state's electricity requirements through the year 2000 without constructing a new fossil-fueled facility (WPSC Order 05-EP-03, May 23, 1983, p. 6). To do so, the WPSC is in the process of implementing an aggressive least-cost planning program and is actively promoting the development of conservation, cogeneration, and renewable energy. The WPSC has estimated that 450 MW of renewables and 3800 MW of cogeneration might be added by 2002 (WPSC Order 05-EP-4, August 8, 1986, p. 17).

II. STATE UTILITY REGULATORY AUTHORITY

The WPSC has jurisdiction over the following:

- Setting utility retail electric rates
- Approving or denying utility cost recovery initiatives
- Overseeing utility resource and capacity expansion plans
- Issuing permits for new power plants

(Personal Communication, David Schoengold, Wisconsin PSC, October 1, 1986)

III. REGULATION OF UTILITY ACTIVITIES

Resource Planning

In August 1986, the WPSC adopted least-cost planning as its method for evaluating power supply and demand options. Least-cost planning, according to the WPSC, does not separate supply-side (new generating facilities, transmission lines) from demand-side (energy conservation) options. In addition, social and environmental costs are estimated, which include health, safety, reliability, and primary and secondary environmental impacts. The WPSC has instructed Wisconsin utilities to include least-cost planning in their next advance plan due in 1987 (WPSC 05-EP-4, August 8, 1986, pp. 7, 21-22). A utility-sponsored conference on least cost planning was held December 10, 1986 to explore issues and options (Personal Communication, David Schoengold, Wisconsin Public Service Commission, October 1, 1986).

Utilities must file a biennial plan that forecasts energy and peak demand requirements over the next 20 years, states intentions for building new generation facilities for the next 15 years, outlines plans to construct new transmission facilities for the next 10 years, and analyzes alternatives to constructing new generating and transmission facilities.

Joint plans may be submitted by two or more utilities. Three groups currently submit plans to the WPSC:

- Eastern Wisconsin Utilities (EWU), consisting of utilities serving the eastern two-thirds of Wisconsin: Madison Gas and Electric, Wisconsin Electric Power Co., Wisconsin Power and Light, and Wisconsin Public Service Corp.
- Western Wisconsin Utilities (WWU), which is essentially the rest of the state not covered by EWU: Dairyland Power Cooperative; Lake Superior District Power co; Northern States Power (Minnesota); Northern States Power (Wisconsin); and Superior Water, Light and Power Co.
- Wisconsin Public Power, Inc. (WPPI), composed of 29 municipals throughout the state.

(WPSC Order 05-EP-03, May 23, 1983, pp. 1-2).

Power Plant Certification

A proposed central station facility must meet cost/benefit tests under Wisconsin's least cost planning program, must be in the utility's advance plan, and be "in the public interest" (Personal Communication, David Schoengold, Wisconsin Public Service Commission, November 5, 1986).

For a utility to receive approval for a conventional-fired facility, it must show why part of the supply cannot be furnished by "alternative, non-depletable" energy sources, or clean-coal technologies (WPSC Order 05-EP-03, May 23, 1983, Appendix C, pp. 1-2).

All siting studies and applications for conventional-fired plants must have information on the availability of sites for renewable or cogeneration technologies. In addition, the utility must explain how it evaluated these sites (WPSC Order 05-EP-03, May 23, 1983, p 4).

Before a new fossil-fired power plant (excluding cogeneration) can be filed, at least 30% of the electric water heaters served by the filing utilities must be under load control for purposes of disconnection at peak times, if necessary (WPSC Order 05-EP-03, May 23, 1983, p. 38).

No nuclear energy facilities are allowed to be planned or applied for until the issues of waste disposal, fuel supply, and decommissioning are addressed to the WPSC's satisfaction (WPSC Order 05-EP-03, May 23, 1983, Appendix C, p. 1).

Cost Recovery

Payments made to customer-owned generating systems (COGS, Wisconsin's term for QFs) can be recovered by utilities through the fuel adjustment clause (WPSC Order 05-ER-11/12/13, June 23, 1983).

Research and Development Expenditures

The WPSC has directed utilities to aggressively research, develop, and promote renewable technologies. The next advance plan, due in 1987, must have cost and potential capacity data for

hydropower, wood waste, wind, photovoltaics, solid waste, and cogeneration. Also, the WPSC has ordered utilities to continue a wind monitoring program begun in 1983 and issue semi-annual reports on their findings to the WPSC. Studies must also be performed on the capability and cost of converting fossil-fueled facilities to solid waste. Further reports must be prepared on the potential of cogeneration, especially small, standardized systems, and the the possible capacity and location of these systems in each utility region (WPSC Order 05-EP-04, August 8, 1986, pp. 17-19, 54-55).

Utility Diversification into Non-Regulated Businesses

In the most recent state legislative session, a bill was passed and signed into law that allowed utilities to set up holding companies. Wisconsin utilities are now organizing such holding companies with direct participation. Although the WPSC has not taken a stand on this issue (Personal Communication, David Schoengold, Wisconsin Public Service Commission, November 5, 1986), the WPSC did deny the Wisconsin Public Service Company from establishing unregulated subsidiaries to develop cogeneration projects with customers (WSPUC, Order NO. 6690-DR-100, April 18, 1985).

IV. IMPLEMENTATION OF PURPA

QF Definition

All COGS are eligible for avoided cost payments, regardless of when they were installed, their capacity, or whether they meet the FERC "qualifying facility" definition (WPSC 05-ER-11/12/13, June 23, 1983, p. 53).

Utility Ownership of QFs

In March 1985, the WPSC ruled that any project 50% or more utility-owned will be considered a utility and hence subject to state utility regulations (Phipps Group, State Summaries of Major Cogeneration Issues, 1985).

Avoided Cost and Buy-Back Rates

COGS can sell power to utilities in Wisconsin through three methods:

- COGS under 20 kW can sell power under a net billing arrangement
- A COGS and a utility can negotiate and sign a contract
- COGS can sell power to the utility at WPSC avoided cost rates

(NARUC Response)

The WPSC may set avoided costs by estimating the costs of a deferred coal plant, an oil-fired peaking facility, or a combination of both (WPSC, *Alternative Electric Power Supply Study--Update 1985*, pp. 109-110). Because a new baseload coal facility is not expected until the late 1990s, the oil peaker method is currently the standard used (Personal Communication, David Schoengold, Wisconsin Public Service Commission, October 1, 1986). Avoided capacity costs are set by calculating 75% of the marginal cost for a utility to add new capacity (Personal Communication, David Schoengold, Wisconsin Public Service Commission, November 5, 1986).

Avoided cost rates differ with regard to peak (high demand) and off-peak (low demand) service. Off-peak rates are defined as a utility's marginal energy costs averaged over off-peak hours. On-peak rates are determined by measuring 75% of a utility's marginal capacity costs averaged over all on-peak hours (WPSC 05-ER-11/12/13, June 23, 1983, pp. 50-51). Currently, off-peak rates are approximately 2.0-2.5¢/kWh, while peak is 4.5-5.0¢/kWh (Personal Communication, David Schoengold, Wisconsin Public Service Commission, October 1, 1986).

Small and municipal utilities pay only the avoided cost of their wholesale energy suppliers, rather than the purchase price. Smaller COGS operate under net billing arrangements, while larger COGS must negotiate directly with the utility. If an agreement cannot be reached, then the QF can ask the utility to wheel to another utility willing to purchase the energy or capacity. The QF must reimburse the wheeling utility for any costs incurred (WPSC 05-ER-11, August 27, 1984, p. 5-7).

Standard Contracts

No contract is required if the COGS is operating under WPSC-set avoided cost rates or under a net billing arrangement. If a COGS negotiates a contract with a utility, the contract must include performance clauses (WPSC Order 05-ER-11, August 27, 1984, pp. 2-3).

Interconnection Requirements

Interconnection costs are negotiated between the utility and the COGS, with any disputes to be resolved by the WPSC. All costs must be paid by the COGS, either directly or in installments up to 2 years. If the latter option is chosen, then COGS must pay a finance charge (WPSC 05-ER-11/12/13, pp. 51, 53). A monthly charge will also be assessed the COGS for installation and metering (WPSC 05-ER-11. August 27, 1984, p. 51). The COGS must take out a minimum $100,000 liability insurance and/or provide proof of financial responsibility (WPSC 05-ER-11, August 27, 1984, p. 2).

Back-Up Rates and Service

COGS are charged standard tariffs depending on their classification, e.g., residential, industrial, or commercial.

Wheeling QF Power

The WPSC is unsure of its jurisdiction over wheeling, so it has largely been quiet on the issue except for small and municipal utilities--see "Avoided Cost" section. The issue of wheeling power directly to another COGS or to an end-user has not prompted action, but it is felt the WPSC staff would not be in favor of such a policy (Personal Communication, David Schoengold, Wisconsin Public Service Commission, October 1, 1986).

WISCONSIN

Transmission Availability and System Upgrades

There are some concerns about adequate transmission capacity in some parts of the state. The WPSC is currently studying the issue (Personal Communication, David Schoengold, Wisconsin Public Service Commission, October 1, 1986).

Performance Requirements and Security Payments

There are no QF non-performance provisions other than what may be negotiated on a case-by-case basis between the COG and a utility (Personal Communication, David Schoengold, November 5, 1986).

RENEWABLE ELECTRIC DEVELOPMENT BY STATE

To show the scope and distribution of renewable electric systems in the U.S., the Renewable Energy Institute (REI) has compiled a state-by-state list of currently installed, grid-connected U.S. renewable electric installations. An early draft, using information collected from industry trade sources, industry analysts, conference proceedings, government data bases, and government publications was mailed to state energy and utility regulatory offices for their comments. Their suggested revisions were incorporated into the final product.

The renewable electric technologies covered in this list include biomass, geothermal, hydropower, solar, and wind. These are further subdivided into system types: Biomass into anaerobic digestion, landfill gas, municipal solid waste (MSW), and wood/agricultural waste; geothermal into binary, dry steam, dual flash, and single flash; hydro into small (<30 MW) and large (>30 MW); solar into photovoltaics and solar thermal; wind into small wind energy conversion systems or SWECS (individual units <15 kW), wind farms (individual units >15 kW), and multi-megawatt (individual units >1 MW). Each system type is measured by the number of units installed and on-line, the total installed nameplate capacity, and the average size of each unit. Should there be only a single known installation, the project's name or location is provided.

A further distinction has been made between federal, DOE, non-utility, state/local, and utility-owned and/or sponsored renewable electric systems. Federal systems are almost exclusively hydro projects developed by the U.S. federal government, notably the U.S. Army Corp of Engineers. U.S. Department of Energy, has built several demonstration renewable electric systems that generate electricity, such as the Solar One facility near Barstow, California and the multi-megawatt wind turbines in Medicine Bow, Wyoming and Goldendale, Washington. Non-utility systems are privately financed and developed facilities that other parties may refer to as "independent" or "small energy producers." Small in capacity, they are usually recent installations stimulated in large part by the enactment of PURPA in 1978. State/local projects refers to facilities funded and/or developed by irrigation districts and city or county governments. These too tend to be almost entirely hydro facilities. Utility projects are those financed and built by municipal, public, investor-owned, or rural electric utilities.

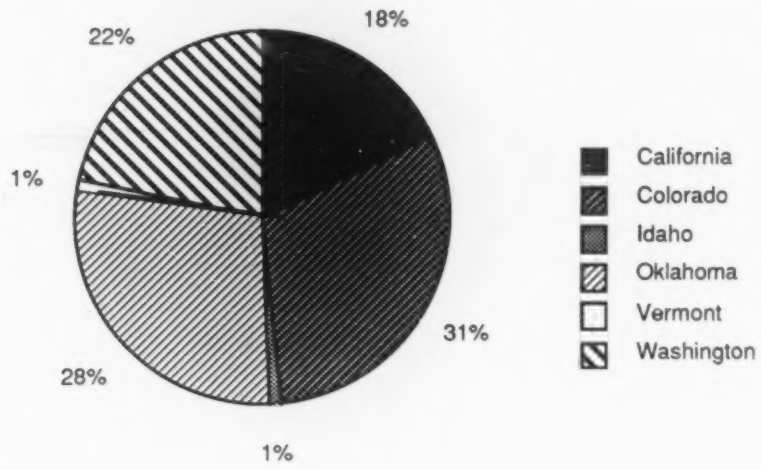
REI has attempted to make this list as comprehensive as possible. The distributed and diffuse nature of some renewable electric systems, especially remote wind and photovoltaic systems, makes collecting data a difficult task. Therefore, this compilation represents a "best-guess" estimate of where, what, and how much of each renewable technology is currently operating in each state. REI hopes to update this assessment periodically and would welcome any comments or suggestions.

Renewable Energy Technology by State (MWe)

State	Anaerobic	Landfill Gas	MSW	Wood/Ag Waste	Geothermal	Lg Hydro	Sm Hydro	PV	Solar Ther	Wind	Total
Alabama		0		342.5		3241.2	8.3				3592
Alaska				2.1		74.2	207.1			0.03	283.43
Arizona						2085.9	73.7	0.44		0.02	2160.06
Arkansas				1.81		1151.5	36.5	0.25		0.03	1190.09
California	3.25	37.5		175.7	1522.5	7317.6	882.4	10.39	58.8	1154.28	11162.42
Colorado	5.5					332.8	146.6				484.9
Connecticut			3.4	0.15		67.7	54.2				125.45
Delaware							0.5			0.01	0.51
Dist of Col.								0.3			0.3
Florida			195.9	488.1			41.07	0.07			725.14
Georgia				93.5		1924.4	188.5		0.43		2206.83
Hawaii				197.7	3		18.47			17.08	236.25
Idaho	0.15			61.8		2480.4	266.4			0.03	2808.78
Illinois							24.2				24.2
Indiana						81	24				105
Iowa			6.3								6.3
Kansas							1.9			3.85	5.75
Kentucky				1		716.32	2				719.32
Louisiana				141.5							141.5
Maine				541		226.9	332.7				1100.6
Maryland			47			707.6	19.6	0.2			774.4
Massachusetts			135.7	3		167	160.7	0.98		0.66	468.04
Michigan				22.4			341.8				364.2
Minnesota		3	0.9	9		70.9	132.3			0.2	216.3
Mississippi				80							80
Missouri						353.2	30				383.2
Montana				14.5		2850.2	44.76			0.58	2910.04
Nebraska						278.1	43.8	0.03		0.1	322.03
Nevada					30.6	2004	6.83		0.03		2041.46
New Hampshire			10.3	33.2		443	181.6	0.01		25.3	693.41
New Jersey		2.4					3.1				5.5
New Mexico					0		12.3	0.2		0.52	13.02
New York		6.4	143			3635.8	743.9			4.95	4534.05
North Carolina		0.17	6.2	55		1653.6	164.4				1879.37
North Dakota				10		430					440
Ohio	5	0.1	42	16.5		118.3	6.45	0.03			188.38
Oklahoma			2.9	0.9		731	0.92	0.15			735.87
Oregon			11.3	366.2		6446.7	508.7	0.01		1.34	7334.25
Pennsylvania			7.7	18		818.3	61.3				905.3
Puerto Rico							5				5
Rhode Island							8.8				8.8
South Carolina				48.5		1094.3	160.8				1303.6
South Dakota											0
Tennessee			7.1	2.5		1971.9	106.5				2088
Texas			1.8	36		439	40.7	0.05		0.13	517.68
Utah					22.7	108	84	0.1			214.8
Vermont	0.14	0.25		73		74.4	132.3			0.05	280.14
Virginia				29		626.5	115.7	0.06		0	771.26
Washington	3.9			208.7		23338.58	136.3			7.5	23694.98
West Virginia						153.2	55.75				208.95
Wisconsin			9.1	116		148.4	296.6			0.05	570.15
Wyoming						165	63.01			6.5	234.51
											0
U.S. TOTAL	17.94	49.82	630.6	3189.26	1578.8	68526.9	5976.46	13.27	59.25	1223.2	81265.5

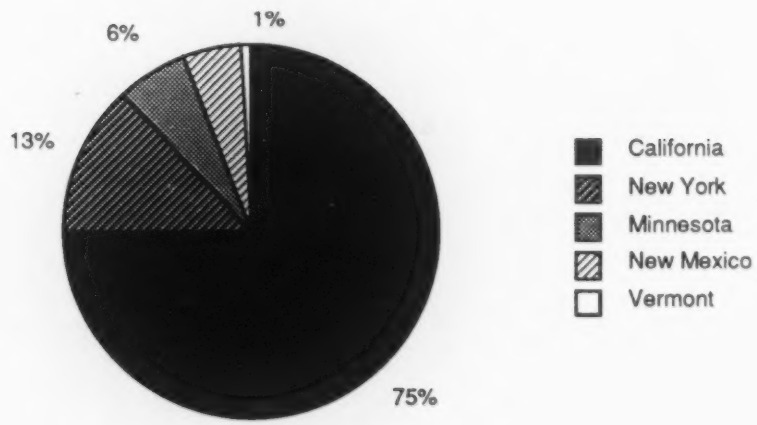
Leading Anaerobic Digestion States

(17.94 MWe Total)



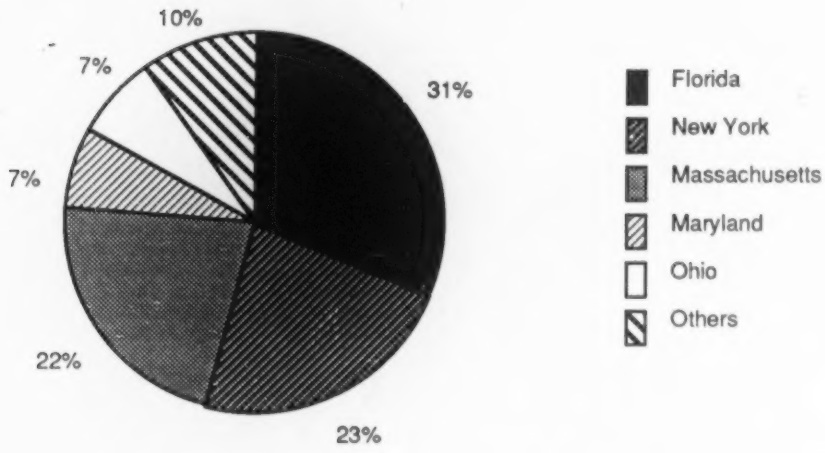
Leading Landfill Gas States

(49.82 MWe Total)



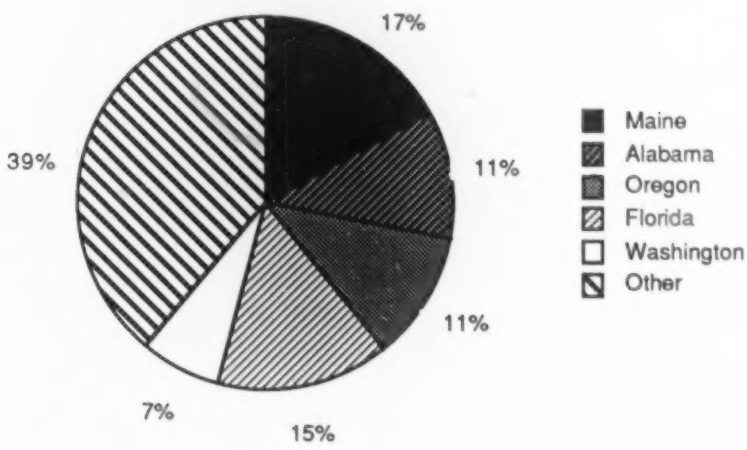
Leading MSW States

(630.6 MWe Total)

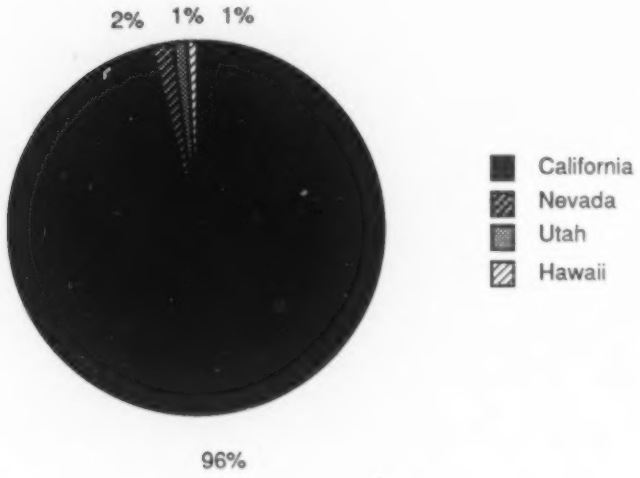


Leading Wood/Ag Waste States

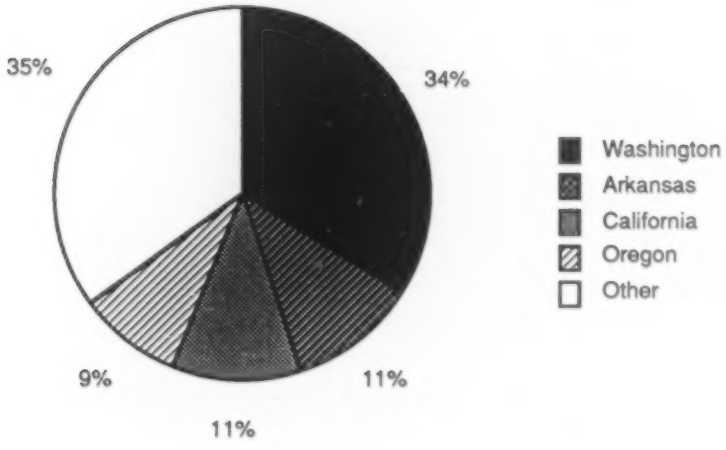
(3189.26 MWe Total)



Leading Geothermal States
(1578.8 MWe Total)

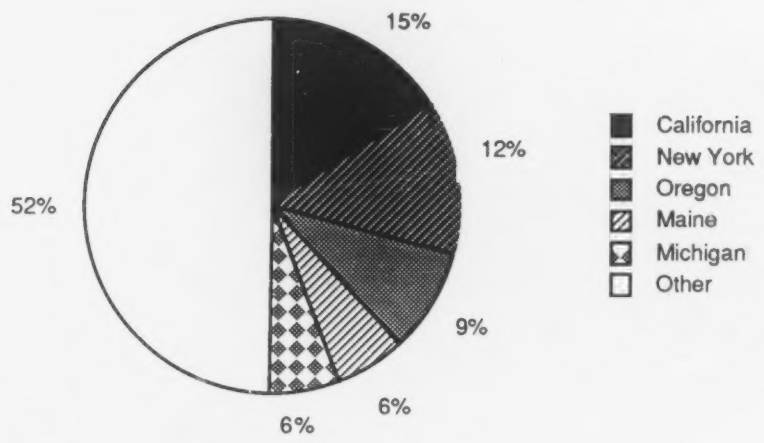


Leading Large Hydro States
(68526.9 MWe Total)



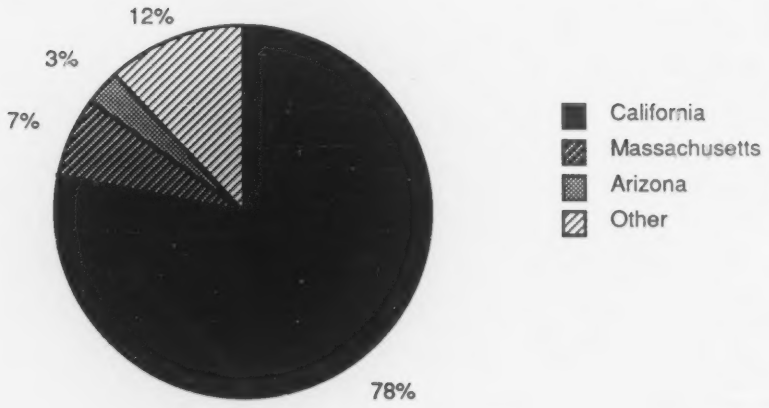
Leading Small Hydro States

(5976.46 MWe Total)



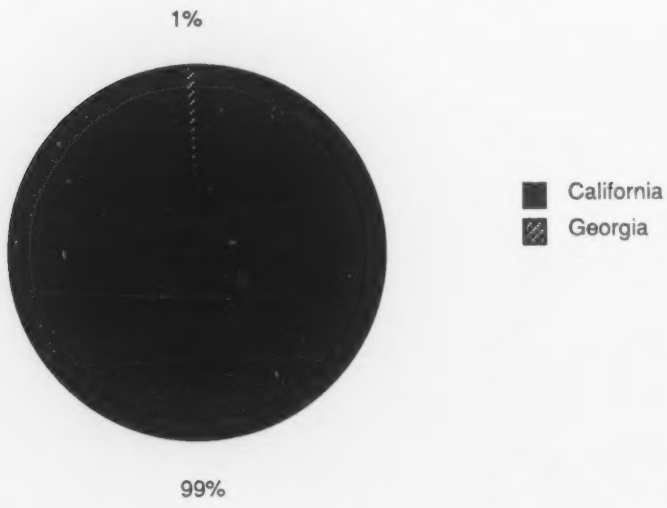
Leading PV States

(13.27 MWe Total)



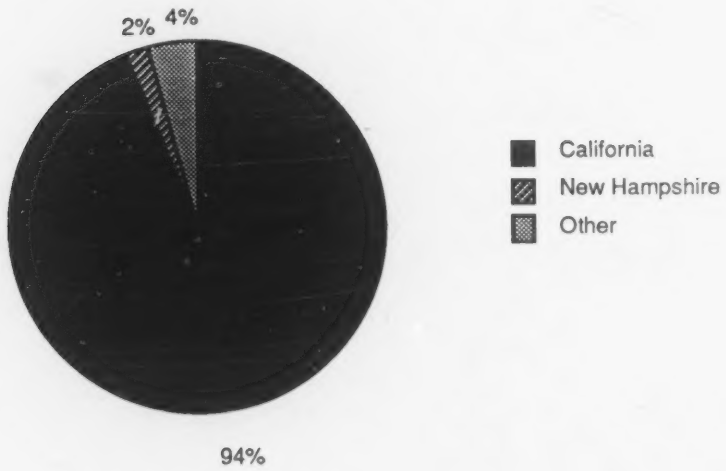
Leading Solar Thermal States

(59.25 MWe Total)



Leading Wind States

(1223.2 MWe Total)



RENEWABLE ELECTRIC DEVELOPMENT BY STATE

1985/1986

ALABAMA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste		Non-Utility	342.5	7	48.9
Hydro	Large (>30 MWe)		Federal	1247.0	5	249.4
			Utility	1994.2	14	142.4
	Small (<30 MWe)		Utility	8.3	2	4.2

ALASKA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste		Non-Utility	2.0	1	2.0
			Utility	0.1	1	0.1
Hydro	Large (>30 MWe)	Snettisham	Federal	74.2	1	74.2
	Small (<30 MWe)	Eklutra	Federal	30.0	1	30.0
			Non-Utility	1.7	8	0.2
			Utility	175.4	16	10.9

ALASKA, cont'd

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Wind	SWECS	Unalaklett Valley	Utility	0.03	3	0.01

ARIZONA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Hydro	Large (>30 MWe)		Federal	2085.9	3	695.3
	Small (<30 MWe)		Federal	35.5	2	17.8
			Non-Utility	9.4	3	3.1
		Remmel	Utility	29.0	1	29.0
Solar	Photovoltaics	Papago	DOE	0.004	1	0.004
		Sky Harbor	DOE	0.23	1	0.23
		John Long		0.19	1	0.19
			Non-Utility	0.013	4	0.003
Wind	SWECS		Non-Utility	0.023	2	0.012

ARKANSAS

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste		Non-Utility	1.81	3	0.6
Hydro	Large (>30 MWe)		Federal	1092.5	8	136.6
		Carpenter	Utility	59.0	1	59.0
	Small (<30 MWe)	Narrows	Federal	25.5	1	25.5
		Remmel	Utility	11.0	1	11.0
Solar	Photovoltaics	Blytheville	DOE	0.25	1	0.25
Wind	SWECS		Non-Utility	0.027	2	0.013

CALIFORNIA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Anaerobic Digestion	Palm Springs	Non-Utility	0.25	1	0.25
		Scattergood	Utility	3.0	1	3.0
	Landfill Gas		Non-Utility	37.5	13	2.9
	Wood/Ag Waste		Non-Utility	174.4	16	10.9
		Highgrove	Utility	1.3	1	1.3
Geothermal	Binary	Imperial Valley	Non-Utility	12.5	1	12.5
		Heber	DOE/Utility	45.0	1	45.0
		Mammoth-Pacific	Non-Utility	7.0	2	3.5

CALIFORNIA, cont'd

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Geothermal (cont'd)	Dry Steam	Geysers	Non-Utility	80.0	1	80.0
		Geysers	Utility	1319.0	16	82.4
	Dual Flash	Heber	Non-Utility	49.0	1	49.0
	Single Flash	Imperial Valley	Util/Non-Util	10.0	1	10.0
Hydro	Large (>30 MWe)		Federal	1754.3	9	194.9
			Utility	5563.3	35	158.9
	Small (<30 MWe)		Federal	15.5	2	7.7
			Non-Utility	12.7	39	0.3
			Utility	854.2	140	6.1
Solar	Photovoltaics	Carissa Plain	Non-Utility	7.3	1	7.3
		Hesperia	Non-Utility	1.0	1	1.0
		Mt. Laguna	DOE	0.06	1	0.06
		Rosemead	Utility	0.03	1	0.03
		SMUD	Utility	2.0	2	1.0
	Solar Thermal	Daggett	Non-Utility	0.025	1	0.025
		Daggett	DOE/Utility	10.0	1	10.0
		Daggett	Non-Utility	43.8	1	43.8
		Huntington	Non-Utility	0.05	2	0.025
		Rosemead	Non-Utility	0.025	1	0.025
		Warner Springs	Non-Utility	4.9	1	4.9
Wind	Multi-Megawatt	Solano	Utility	2.5	1	2.5

CALIFORNIA, cont'd

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Wind (cont'd)	Wind Farm	Altamont	Non-Utility	576.0	5676	0.1
		Boulevard	Non-Utility	0.7	27	0.03
		Carquinez Strait	Non-Utility	0.62	6	0.1
		Salinas Valley	Non-Utility	0.16	4	0.04
		San Gorgonio	Non-Utility	272.9	3973	0.07
		Tehachapi	Non-Utility	301.4	3713	0.08

COLORADO

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Anaerobic Digestion	Denver Sewage	Non-Utility	5.5	1	5.5
Hydro	Large (>30 MWe)		Federal	332.8	5	66.6
	Small (<30 MWe)		Federal	80.1	6	13.4
			Non-Utility	1.7	6	0.3
			Utility	64.8	13	4.9

CONNECTICUT

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste	Guilford	Non-Utility	0.15	1	0.15
	MSW	Windham	Non-Utility	3.4	1	3.4
Hydro	Large (>30 MWe)		Utility	67.7	2	33.9
	Small (<30 MWe)		Non-Utility	4.3	4	1.1
			Utility	49.9	9	5.5

DELAWARE

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Hydro	Small (<30 MWe)	Hagley	Non-Utility	0.5	1	0.5
Wind	SWECS		Non-Utility	0.0098	3	0.003

DISTRICT OF COLUMBIA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Solar	Photovoltaics	Georgetown	DOE	0.3	1	0.3

FLORIDA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste		Non-Utility	488.1	15	32.5
	MSW		Non-Utility	195.9	5	39.2
Hydro	Small (<30 MWe)	Jim Woodruff	Federal	30.0	1	30.0
		Blue Springs	Non-Utility	0.168	1	0.168
		Jackson Bluff	Utility	10.9	1	10.9
Solar	Photovoltaics	EPCOT	Utility	0.07	1	0.07

GEORGIA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste		Non-Utility	93.5	2	46.8
Hydro	Large (>30 MWe)		Federal	1328.4	7	189.8
			Utility	596.0	7	85.1
	Small (<30 MWe)		Federal	35.0	2	17.5
			Non-Utility	12.1	8	1.5
			Utility	141.4	13	10.9
Solar	Solar Thermal	Shenandoah	Non-Utility	0.025	1	0.025
		STEP	Utility	0.4	1	0.4

HAWAII

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste	Waialua Sugar	Utility	12.5	1	12.5
			Non-Utility	185.2	13	14.2
Geothermal	Single Flash	Abbott	Non-Utility	3.0	1	3.0
Hydro	Small (<30 MWe)		Non-Utility	15.122	15	1.01
			Utility	3.35	4	0.84
Wind	Wind Farm		Non-Utility	16.74	425	0.04
		Maalaea	Utility	0.34	1	0.34

IDAHO

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Anaerobic Digestion	Pocatello	Non-Utility	0.15	1	0.15
	Wood/Ag Waste		Non-Utility	61.8	4	15.4
Hydro	Large (>30 MWe)		Federal	1261.4	4	315.4
			Utility	1219.0	8	152.4
	Small (<30 MWe)		Federal	22.9	3	7.6
			Non-Utility	56.3	50	1.1
			Utility	187.2	23	8.1
Wind	SWECS		Non-Utility	0.027	2	0.013

ILLINOIS

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Hydro	Small (<30 MWe)	Rock Island	Federal	2.7	1	2.7
		Rockton	Non-Utility	1.1	1	1.1
			Utility	20.4	3	6.8

INDIANA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Hydro	Large (>30 MWe)	Markland	Utility	81.0	1	81.0
	Small (<30 MWe)		Utility	24.0	2	12.0

IOWA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	MSW	Ames Plant (MSW/Coal)	Utility	6.3	1	6.3

KANSAS

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Hydro	Small (<30 MWe)	Kansas River	Non-Utility	1.9	1	1.9
Wind	SWECS		Non-Utility	3.8	241	0.015
	SWECS	Wilson	Utility	0.05	2	0.03

KENTUCKY

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste	Dickerson	Non-Utility	1.0	1	1.0
Hydro	Large (>30 MWe)		Federal	636.0	4	159.0
		Ohio Falls	Utility	80.32	1	80.32
	Small (<30 MWe)	Kentucky L&D #7	Non-Utility	2.0	1	2.0

LOUISIANA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste		Non-Utility	141.5	4	35.4

MAINE

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste		Non-Utility	541.0	29	18.7
Hydro	Large (>30 MWe)	Ripogenus	Non-Utility	37.5	1	37.5
			Utility	189.4	2	63.1
	Small (<30 MWe)		Non-Utility	112.6	47	2.4
			Utility	220.1	38	5.8

MARYLAND

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	MSW	Baltimore	Non-Utility	47.0	1	47.0
Hydro	Large (>30 MWe)	Conowingo	Non-Utility	707.6	1	707.6
	Small (<30 MWe)	Gilpin Falls	Non-Utility	0.4	1	0.4
		Deep Creek	Utility	19.2	1	19.2
Solar	Photovoltaics	Solarex	Private	0.2	1	0.2

MASSACHUSETTS

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste	Pittsfield	Non-Utility	3.0	1	3.0
	MSW		Non-Utility	135.7	13	10.4
Hydro	Large (>30 MWe)	Jonesville	Non-Utility	51.0	1	51.0
			Utility	116.0	3	38.7
	Small (<30 MWe)		Non-Utility	43.0	30	1.4
			Utility	117.7	23	5.1
Solar	Photovoltaics	Beverly	DOE	0.1	1	0.1
		Gardner	Utility	0.86	35	0.025
		MassPUP	State	0.0243	242	0.001
Wind	SWECS	Hull	Non-Utility	0.01	1	0.01
	Wind Farm	Nantucket	Non-Utility	0.33	9	0.04
		Princeton	Non-Utility	0.32	8	0.04

MICHIGAN

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste	Midland	Non-Utility	22.4	1	22.4
Hydro	Small (<30 MWe)	St. Mary's Falls	Federal	18.4	1	18.4
			Non-Utility	35.5	16	2.2
			Utility	287.9	50	5.8

MINNESOTA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Landfill Gas	Anoka County	Non-Utility	3.1	3.0	
	MSW	Collegeville	Non-Utility	0.9	1	0.9
	Wood/Ag Waste	Fergus Falls	Non-Utility	9.0	1	9.0
Hydro	Large (>30 MWe)	Thomson	Utility	70.9	1	70.9
	Small (<30 MWe)		Non-Utility	61.2	9	6.8
			Utility	71.1	12	5.9
Wind	Wind Farm	Northern Power	Utility	0.19	3	0.065

MISSISSIPPI

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste		Non-Utility	80.0	5	16.0

MISSOURI

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Hydro	Large (>30 MWe)	Stockton	Federal	45.2	1	45.2
			Utility	308.0	2	154.0
	Small (<30 MWe)	Cannon	Federal	27.0	1	27.0
		Niangua	Utility	3.0	1	3.0

MONTANA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste	Libby Plant	Utility	14.5	1	14.5
Hydro	Large (>30 MWe)		Federal	1860.3	6	310.1
			Utility	989.9	9	110.0
	Small (<30 MWe)	Big Creek	Federal	0.36	1	0.36
			Non-Utility	0.6	4	0.15
			Utility	43.8	7	6.3
Wind	SWECS		Non-Utility	0.375	21	0.018
	Wind Farm	Livingston	Utility	0.125	5	0.25
		Livingston	Non-Utility	0.08	2	0.04

NEBRASKA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Hydro	Large (>30 MWe)	Gavins Point	Federal	100.0	1	100.0
			Utility	178.1	4	44.5
	Small (<30 MWe)		Utility	43.8	3	14.6
Solar	Photovoltaics	Mead	DOE	0.03	1	0.03
Wind	SWECS		Non-Utility	0.104	18	0.006

NEVADA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Geothermal	Binary		Non-Utility	5.6	2	2.8
	Dual Flash		Non-Utility	25.0	2	12.5
Hydro	Large (>30 MWe)		Federal	2004.0	3	668.0
	Small (<30 MWe)		Non-Utility	0.225	1	0.225
			Utility	6.6	4	1.65
Solar	Solar Thermal		Non-Utility	0.025	1	0.025

NEW HAMPSHIRE

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste		Non-Utility	33.2	6	5.5
	MSW	PRS-Derry	Non-Utility	10.3	1	10.3
Hydro	Large (>30 MWe)		Utility	443.0	4	110.8
	Small (<30 MWe)		Non-Utility	73.8	82	0.9
			Utility	107.8	11	9.8
Solar	Photovoltaics	Residential	Non-Utility	0.0086	1	0.0086
Wind	SWECS/Wind Farm		Non-Utility	25.3	22	1.15

NEW JERSEY

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Landfill Gas		Non-Utility	2.4	2	1.2
Hydro	Small (<30 MWe)	Little Falls	Utility	3.1	1	3.1

NEW MEXICO

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Geothermal		Gila Hot Springs	Non-Utility	0.001	1	0.001
Hydro	Small (<30 MWe)	Elephant Butte	Federal	12.0	1	12.0
			Non-Utility	0.30	4	0.075
Solar	Photovoltaics	Albuquerque	DOE	0.05	1	0.05
		Las Cruces	DOE	0.047	1	0.047
		Lovington	DOE	0.1	1	0.1
		Residential	Non-Utility	0.005	75	0.375
Wind	SWECS		Non-Utility	0.286	41	0.007
	Darrieus/VAWT		Non-Utility	0.235	2	0.118

NEW YORK

Technology	System Type	Project	Owner/ Operato-	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Landfill Gas		Non-Utility	6.4	6	1.1
	MSW		Non-Utility	140.4	5	28.1
			Utility	2.6	1	2.6
Hydro	Large (>30 MWe)		Non-Utility	170.5	3	56.8
			Utility	3465.3	10	346.5

NEW YORK, cont'd

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Hydro (cont'd)	Small (<30 MWe)		Non-Utility	111.6	41	2.7
			Utility	632.3	91	6.9
Wind	SWECS		Non-Utility	4.95	132	0.04

NORTH CAROLINA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Landfill Gas	Natural Power	Non-Utility	0.17	1	0.17
	MSW	New Hanover	Non-Utility	6.2	1	6.2
	Wood/Ag Waste	Riegelwood	Non-Utility	55.0	1	55.0
Hydro	Large (>30 MWe)		Federal	296.1	2	148.1
			Non-Utility	357.9	6	59.7
			Utility	999.6	9	111.1
	Small (<30 MWe)	Chatuge	Federal	10.0	1	10.0
			Non-Utility	12.9	18	0.7
			Utility	141.5	20	7.1

NORTH DAKOTA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste	Enderlin	Non-Utility	10.0	1	10.0
Hydro	Large (>30 MWe)	Garrison	Federal	430.0	1	430.0

OHIO

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Anaerobic Digestion	Columbus	Utility	5.0	1	5.0
	Landfill Gas	Broadview Hts.	Non-Utility	0.1	1	0.1
	MSW	Columbus	Non-Utility	42.0	1	42.0
	Wood/Ag Waste	Coshocton	Non-Utility	16.5	1	16.5
Hydro	Large (>30 MWe)		Utility	118.3	2	59.2
	Small (<30 MWe)	Defiance	Non-Utility	4.2	1	4.2
		Hamilton	Utility	2.25	1	2.25
Solar	Photovoltaics	Bryan	DOE	0.03	1	0.03

OKLAHOMA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	MSW	Okla. City	Non-Utility	2.9	1	2.9
	Wood/Ag Waste	Braum	Non-Utility	0.9	1	0.9
Hydro	Large (>30 MWe)		Federal	536.6	7	76.7
			Utility	194.4	2	97.2
	Small (<30 MWe)	Lake Altus	Utility	0.92	1	0.92
Solar	Photovoltaics	Okla. City	DOE/Private	0.15	1	0.15

OREGON

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste		Non-Utility	315.0	34	9.3
		Weyco	Utility	51.2	1	51.2
	MSW	Salem	Non-Utility	11.3	1	11.3
Hydro	Large (>30 MWe)		Federal	4941.1	9	549.0
			Utility	1505.6	11	136.8
	Small (<30 MWe)		Federal	99.0	5	19.8
			Non-Utility	32.0	29	1.1
			State/Local	31.6	12	2.6
			Utility	288.5	19	15.2

OREGON, cont'd

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Solar	Photovoltaics	Redmond	DOE	0.01	1	0.01
			Non-Utility	0.0014	1	0.0014
Wind	SWECS		Non-Utility	0.086	23	0.0037
	Wind Farm	Whiskey Run	Non-Utility	1.2	24	0.05

PENNSYLVANIA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	MSW	Harrisburg	Non-Utility	7.7	1	7.7
	Wood/Ag Waste		Non-Utility	18.0	3	6.0
Hydro	Large (>30 MWe)		Utility	818.3	4	204.6
	Small (<30 MWe)		Non-Utility	6.4	4	1.6
			Utility	54.9	2	27.5

PUERTO RICO

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Hydro	Small (<30 MWe)	Rio Blanco	Utility	5.0	1	5.0

RHODE ISLAND

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Hydro	Small (<30 MWe)		Non-Utility	6.0	10	0.6
			Utility	2.8	2	1.4

SOUTH CAROLINA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste	Fine Paper	Non-Utility	48.5	1	48.5
Hydro	Large (>30 MWe)		Federal	364.0	2	182.0
			Utility	730.3	8	91.3
	Small (<30 MWe)		Non-Utility	22.2	3	7.4
			Utility	138.6	12	11.6

SOUTH DAKOTA

None Reported

TENNESSEE

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	MSW		Non-Utility	7.1	2	3.5
	Wood/Ag Waste		Non-Utility	2.5	3	0.8
Hydro	Large (>30 MWe)		Federal	1971.9	21	93.9
	Small (<30 MWe)		Federal	106.5	5	21.3

TEXAS

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste		Non-Utility	36.0	4	9.0
	MSW	Sealy	Non-Utility	1.8	1	1.8
Hydro	Large (>30 MWe)		Federal	324.2	4	81.1
			Utility	114.8	2	57.4
	Small (<30 MWe)	Whitney	Federal	30.0	1	30.0
			Utility	10.7	2	5.4

TEXAS, cont'd

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Solar	Photovoltaics	DFW Airport	DOE/Private	0.03	1	0.03
		El Paso	DOE	0.02	1	0.02
Wind	Wind Farm	Hope Complex	Non-Utility	0.125	5	0.03

UTAH

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Geothermal	Binary	Cove Fort	Non-Utility	2.7	4	0.68
	Single Flash	Blundell #1	Utility	20.0	1	20.0
Hydro	Large (>30 MWe)	Flaming Gorge	Federal	108.0	1	108.0
	Small (<30 MWe)	Deer Creek	Federal	4.9	1	4.9
			Utility	79.1	32	2.5
Solar	Photovoltaics	Natural Bridges	DOE	0.1	1	0.1

VERMONT

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Anaerobic Digestion		Non-Utility	0.135	1	0.135
	Landfill Gas	Brattleboro	Non-Utility	0.25	1	0.25
	Wood/Ag Waste		Utility	73.0	2	36.5
Hydro	Large (>30 MWe)		Utility	74.4	2	37.2
	Small (<30 MWe)		Non-Utility	7.6	21	0.4
			Utility	124.7	85	1.5
Wind	SWECS		Non-Utility	0.05	7	0.007

VIRGINIA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Wood/Ag Waste		Non-Utility	29.0	4	7.3
Hydro	Large (>30 MWe)	John H. Err	Federal	204.0	1	204.0
			Utility	422.5	3	140.9
	Small (<30 MWe)	Philpott	Federal	14.0	1	14.0
			Non-Utility	24.1	11	2.2
			Utility	77.6	14	5.5
Solar	Photovoltaics	North Anna	Utility	0.06	3	0.02

VIRGINIA, cont'd

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Wind	SWECS	Residence	Non-Utility	0.002	1	0.002

WASHINGTON

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	Anaerobic Digestion	West Point	City	3.9	1	3.9
	Wood/Ag Waste	Kettle Falls	Utility	42.5	1	42.5
			Non-Utility	166.2	27	6.2
Hydro	Large (>30 MWe)		Federal	14,389.5	9	1598.8
			Utility	8949.0	29	308.6
	Small (<30 MWe)		Federal	27.5	4	6.9
			Non-Utility	27.5	11	2.5
			Utility	81.3	18	4.5
Wind	Multi-Megawatt	Goldendale	DOE Test	7.5	3	2.5

WEST VIRGINIA

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Hydro	Large (>30 MWe)	Hawks Nest	Non-Utility	102.0	1	102.0
		Lake Lynn	Utility	51.2	1	51.2
	Small (<30 MWe)	Glen Ferris	Non-Utility	5.45	1	5.45
			Utility	50.3	7	7.2

WISCONSIN

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Biomass	MSW	Madison	Non-Utility	2.6	1	2.6
		Blount Street	Utility	6.5	1	6.5
	Wood/Ag Waste		Non-Utility	91.0	6	15.1
		Bayfront	Utility	25.0	2	12.5
Hydro	Large (>30 MWe)		Utility	148.4	4	37.1
	Small (<30 MWe)		Non-Utility	41.5	20	2.1
			Utility	255.1	57	4.5
Wind	SWECS	Fitchburg	Utility	0.01	1	0.01
		Kewaunee	Utility	0.04	1	0.04

WYOMING

Technology	System Type	Project	Owner/ Operator	Total Capacity (MWe)	No. of Installations	Average Size (MWe)
Hydro	Large (>30 MWe)		Federal	165.0	4	41.3
	Small (<30 MWe)		Federal	60.4	6	10.1
		Kinky Creek	Non-Utility	0.01	1	0.01
			Utility	2.6	2	1.3
Wind	Multi-Megawatt	Medicine Bow	Utility	4.0	1	4.0
		Medicine Bow	DOI	2.5	1	2.5

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